2 Description of the Proposed Action

2.0 DESCRIPTION OF THE PROPOSED ACTION

This chapter describes the action proposed by BHP Billiton LNG International Inc. (BHPB or the Applicant) to import liquefied natural gas (LNG) at Cabrillo Port, an offshore floating storage and regasification unit (FSRU) and associated natural gas pipelines, to deliver natural gas to Oxnard, California for distribution in Southern California. Alternatives to the proposed Project are described in Chapter 3.0. Information in this chapter was obtained from the application and subsequent updates to the application for a Deepwater Port (DWP) license at Cabrillo Port.

This chapter is organized as follows. Section 2.1 provides an overview of the proposed Project and its location. Sections 2.2 through 2.4 describe the proposed facilities, and Sections 2.5 through 2.7 provide information on Project construction, including operation and maintenance. Section 2.8 discusses future plans, including decommissioning and abandonment, and Section 2.9 provides a list of references.

This chapter also addresses comments received on the project description during public scoping in March 2004 and during the public review period for the October 2004 Draft Environmental Impact Statement/Environmental Impact Report (EIS/EIR). Representative comments include questions about the FSRU and pipeline design and design standards, containment and management of materials used on the FSRU, ballast water, onshore and offshore construction techniques, natural gas quality and odorant injection, onshore pipeline routes, and decommissioning. Major changes to the project description since the issuance of the October 2004 Draft EIS/EIR include those identified below:

- Due to conceptual design changes, several dimensions of the proposed FSRU are larger than previously proposed by the Applicant, including overall length (from 938 feet or 286 meters [m] to 971 feet or 296 m). These new values are used in the environmental analysis.
- The route of the offshore pipelines has been revised, following geotechnical analyses, to reduce the potential for turbidity flow to affect the pipelines.
- The Applicant would use horizontal directional boring (HDB) instead of horizontal directional drilling (HDD) to install Project pipelines beneath the shore (see Section 2.6.1, "Shore Crossing via HDB" and Section 4.11, "Geologic Resources and Hazards," for further discussion). Cofferdams would not be used.
- The northern portion of the proposed Center Road Pipeline route in Ventura County (beginning at approximately milepost [MP] 12.5 and continuing to Center Road Station) would be relocated to bypass Mesa Union School on Mesa School Road. The proposed route in the October 2004 Draft EIS/EIR is evaluated in this report as Center Road Pipeline Alternative Route 3.
- To assist in leak detection by smell, the Applicant would inject an odorant into the natural gas stream at the FSRU. Southern California Gas Company (SoCalGas) would operate a backup odorant injection system onshore.

- The Applicant would use natural gas instead of diesel fuel as the fuel source for all Project support vessels and has reduced the number of support vessel trips between Port Hueneme and the FSRU.

As part of its project description, BHPB proposes to implement numerous measures to reduce the severity of potential Project-related impacts. (These measures are identified by the prefix “AM” in Chapter 4.0, “Environmental Analysis,” and 6.1, “Recommended Mitigation and Monitoring Program.”) The California State Lands Commission (CSLC), in coordination with the U.S. Coast Guard (USCG) and the U.S. Maritime Administration (MARAD) has also recommended other measures to mitigate for potential significant impacts; these “mitigation measures” are separate from the Applicant’s project description. (For further discussion, see Section 4.1, “Introduction to Environmental Analyses.”)

2.1 PROJECT OVERVIEW AND LOCATION

The proposed Project would have the following main components (see Figure 2.1-1):

Offshore (FSRU)

- Installation and operation of the FSRU, which would be anchored and moored on the ocean floor for the life of the Project in Federal waters 12.01 nautical miles (NM) (13.83 miles or 22.25 kilometers [km]) off the coast of Ventura and Los Angeles Counties, in waters approximately 2,900 feet (884 m) deep. The Applicant selected the proposed location for the FSRU by analyzing known marine hazards, existing pipelines, distances from shore, distances from existing fixed offshore facilities, sea floor slope and topography, and the existing onshore natural gas pipeline infrastructure. The proposed location is outside the traffic separation scheme, i.e., the designated marine traffic lanes for large commercial vessels. Operational activities include:
    - Shipment within the Exclusive Economic Zone of LNG to the FSRU in double-hulled (double-sided and double-bottom) cryogenic tank ships (LNG carriers);
    - Transfer of the LNG from the LNG carriers to the FSRU approximately two to three times per week;
    - Heating of the LNG under controlled conditions to return it to its gaseous form as pipeline-quality natural gas; and
    - Injection of odorant into the natural gas stream.

Shore Crossing and Offshore Pipelines

- Installation of two 24-inch (0.6 m) diameter pipelines from shore, using HDB beneath the surface of the beach, to the FSRU site, and installation and operation of a new onshore metering station with backup odorant injection

Insert (1 of 2)

Figure 2.1-1 Proposed Project Components

Insert (2 of 2)

Figure 2.1-1 Proposed Project Components equipment. The pipelines transporting natural gas from the FSRU to shore would connect to the SoCalGas transmission system at the metering station.

Onshore

- Delivery of the natural gas through (1) a new 36-inch (0.9 m) diameter pipeline constructed within the City of Oxnard and unincorporated areas of Ventura County; (2) a new 30-inch (0.76 m) diameter pipeline loop in the City of Santa Clarita in Los Angeles County; and (3) three expanded or modified existing onshore valve stations. The onshore pipelines and related facilities would be constructed, owned, and operated by SoCalGas, a natural gas utility regulated by the California Public Utilities Commission (CPUC).

Only LNG carrier vessels and the FSRU itself would handle LNG; both the offshore and onshore pipelines would carry only conventional natural gas. The FSRU would be powered by on-board generators, not power cables to or from shore. The Applicant's projected FSRU in-service life is a maximum of 40 years, although the Federal license for the proposed DWP would have no expiration date. Construction of the DWP is proposed to be completed in 2009/2010 with startup projected for 2010.

Table 2.1-1 identifies the general location and specific coordinates for the various Project facilities. Figure 2.1-2 and Table 2.1-2 identify distances from the FSRU to various points of interest. The Project would also require rights-of-way (ROWs) on land and on the seabed for normal operation and maintenance; these requirements are summarized in Table 2.1-3. Additional space that would be required temporarily during construction is listed in Table 2.1-4.

The closest political boundary to the FSRU is Ventura County, the boundary of which is located 3 NM (3.5 miles or 5.6 km) seaward from the mean high tide line. The offshore pipelines pass through Ventura County on lands owned and managed by the State of California, i.e., the CSLC, is from the mean high tide line seaward to 3 NM (3.5 miles or 5.6 miles) offshore where Federal waters commence.

The proposed facilities are described in Sections 2.2 through 2.4, based on their location: offshore (FSRU and vicinity), shore crossing and offshore pipelines, and onshore. The descriptions are not intended to provide engineering specifications for the facilities but, rather, a description of the proposed facilities with sufficient detail that the potential impacts of the proposed facilities can be evaluated.

Although the FSRU design represents a new combination of methods for the transfer and storage of LNG, the individual components that make up the FSRU are not new. At present, a broad range of codes and standards exists for the design, construction/fabrication, and operation of floating production, storage, and offloading (FPSO) units and other floating vessels, facility structures, platforms, and onshore LNG facilities. While no single standard directly addresses the concept of the proposed FSRU, the FSRU is based on existing related facilities, and individual elements are addressed in referenced rules within the Guide for Building and Classing Offshore LNG Terminals (American Bureau of Shipping 2004) as an example, and other applicable

Table 2.1-1 Location of Project Facilities

Facility and Purpose	General Location	Latitude (N)	Longitude (W)
FSRU *Receive and store LNG from tankers; generate power to heat and regasify gas; inject odorant into natural gas stream; send natural gas to shore via pipelines.*	Offshore; Federal waters	33° 51.52’	119° 02.02’
Mooring system *Fix FSRU to seabed*	Offshore; Federal waters	33° 51.52’	119° 02.02’
Riser pipeline-ending manifold *Provide a connection between the FSRU and the offshore pipelines*	Offshore; Federal waters	33° 51.72’	119° 02.62’
Offshore pipelines *Transport natural gas to shore*	Offshore; Federal and State waters	Various	Various
Shore crossing at Ormond Beach *Connect offshore pipelines to proposed onshore metering station*	Ormond Beach, City of Oxnard, Ventura County, California (CA)	HDB entry: 34° 07.69’ HDB exit: 34º 07.19’	HDB entry: 119° 10.03’ HDB exit: 119° 10.69’
Onshore pipelines *Transport natural gas*	Cities of Oxnard and Santa Clarita, Ventura and Los Angeles Counties	Various	Various
Ormond Beach Metering Station and Backup Odorant Station *Measure and transfer ownership of natural gas; inject odorant into natural gas stream if additional odorant is required*	Reliant Energy Ormond Beach Generating Station, City of Oxnard, Ventura County, CA	34° 07.78’	119° 09.98’
Center Road Valve Station *Safety and control*	Ventura County, CA	34° 16.39’	119° 05.60’
Quigley Valve Station Expansion *Safety and control*	Los Angeles County, CA	34° 23.74’	118° 29.88’
Honor Rancho Valve Station *Safety and control*	Los Angeles County, CA	34° 26.66’	118° 35.26’

Source: Ecology and Environment, Inc. 2005.

Note:

Latitude and longitude have been rounded to the nearest 0.01’.

Insert (1 of 2)

Figure 2.1-2 Consequence Distances Surrounding the FSRU Location for Worst Credible Events

Insert (2 of 2)

Figure 2.1-2 Consequence Distances Surrounding the FSRU Location for Worst Credible Events

Table 2.1-2 Distances from FSRU to Points of Interest

Points of Interest	Latitude/Longitude	Calculated Distances to FSRU
FSRU	33°51.52'N - 119°02.02'W	---
Point Mugu Sea Range (eastern boundary, west of FSRU)	33°51.37'N - 119°06.27'W	3.54 NM (4.1 miles or 6.6 km)
Closest point of shipping channel	33°53.43'N - 119°1.12'W	2.06 NM (2.4 miles or 3.8 km)
Malibu City Limits (at coastline and eastern boundary of Leo Carillo State Park)	34°2.71'N - 118°56.63'W	12.05 NM (13.9 miles or 22.3 km)
Eastern Anacapa Island (Channel Island closest to FSRU location)	34°01.01'N - 119°21.31'W	18.61 NM (21.4 miles or 34.5 km)
Channel Islands National Park (statutory 1 NM offshore)	(Distance to FSRU extrapolated from E. Anacapa calculated distance)	17.61 NM (20.3 miles or 32.6 km)
Channel Islands National Marine Sanctuary (statutory 6 NM offshore)[a]	(Distance to FSRU extrapolated from E. Anacapa calculated distance)	12.61 NM (14.5 miles or 23.4 km)

Source: Ecology and Environment, Inc. 2005.

Notes:

NM = nautical miles.

Latitude and longitude have been rounded to the nearest 0.01'.

Two methods were employed to calculate and cross-check distances from the proposed FSRU mooring location to the points of interest identified in this table. A GIS professional calculated distances in ArcGIS using a UTM Zone 11, NAD 83 projection; and a geographer used a combination of a digital raster graphic (DRG) of NOAA Chart #18022, latitude and longitude data from TopoZone.com, a topographic map of Channel Islands National Park (National Geographic Maps 1999), and online navigational calculators available from the National Geospatial Intelligence Agency at http://pollux.nss.nima.mil/calc/calc_options.html. Additionally, both researchers used latitude and longitude data from the Code of Federal Regulations Title 33, Part 167.451 to determine an accurate location of the Traffic Separation Scheme near the Project area. The source is located at: http://www.washingtonwatchdog.org/documents/cfr/title33/part167.html#167.450.

[a] The current boundaries of the Channel Islands National Marine Sanctuary (CINMS) extend from mean high water to 6 NM (6.9 miles or 11.1 km) offshore from the Channel Islands. The CINMS is currently updating its Management Plan and evaluating six different boundary expansion alternatives, which could include the FSRU and subsea pipelines. CINMS has stated that the existence of the FSRU and pipelines would not preclude the sanctuary from including that area within its new boundaries and would be taken into consideration when making the final decision. This subject is addressed in more detail in Section 4.13, "Land Use." The source is located at: http://www.cinms.nos.noaa.gov/manplan/overview.html

Table 2.1-3 Land and Sea Requirements for Construction and Operation of the Cabrillo Port Project

Facility	Installation/Construction		Operation	
	Dimensions	Area	Land Affected	Area
Offshore				
FSRU – proposed safety zone	500 m radius (0.3 NM or 1,640 feet) around FSRU	0.23 square NM (0.3 square miles [mi^2] or 0.8 square kilometers [km^2])	500 m radius (0.3 NM or 1,640 feet) around FSRU	0.23 sq. NM (0.3 mi^2 or 0.8 km^2)
FSRU – proposed Area to be Avoided	2 NM (2.3 miles or 3.7 km) radius	12.6 sq. NM (16.7 mi^2 or 43.3 km^2)	2 NM (2.3 miles or 3.7 km) radius	12.6 sq. NM (16.7 mi^2 or 43.3 km^2)
Subsea transmission pipelines ROW	22.77 miles (36.64 km) by 200 feet (61 m)	553 acres (224 hectares [ha])	22.7 miles (36.64 km) by 200 feet (61 m)	553 acres (224 ha)
Onshore				
Shore crossing	0.8 mile by 50 feet (1.3 km by 15.2 m)	4.9 acres (2.0 ha)	0.8 mile by 50 feet (1.3 km by 15.2 m)	4.9 acres (2.0 ha)
Aboveground facilities at Ormond Beach (metering station, station expansion and modifications, main line block valve, etc.)	400 feet by 400 feet (122 m by 122 m)	3.7 acres (1.5 ha)	200 feet by 200 feet (61 m by 61 m)	0.9 acres (0.4 ha)
Onshore pipeline ROW – Center Road Pipeline[a]	12.6 miles by 80 feet (20.3 km by 24.4 m) and 2.1 miles by 100 feet (3.4 km by 30.5 m)	147.7 acres (59.8 ha)	14.7 miles by 50 feet (23.7 km by 15.2 m)	89.1 acres (36.1 ha)
Onshore pipeline ROW – Line 225 Pipeline Loop[a]	7.7 miles by 80 feet (12.4 km by 24.4 m)	74.8 acres (30.3 ha)	7.7 miles by 50 feet (12.4 km by 15.2 m)	46.6 acres (18.9 ha)
Center Road Valve Station expansion	200 feet by 200 feet (61 m by 61 m)	0.9 acre (0.4 ha)	100 feet by 200 feet (30.5 m by 61 m)	0.5 acre (0.2 ha)
Quigley Valve Station expansion	200 feet by 200 feet (61 m by 61 m)	0.9 acre (0.4 ha)	100 feet by 200 feet (30.5 m by 61 m)	0.5 acre (0.2 ha)
Honor Rancho Valve Station expansion	200 feet by 200 feet (61 m by 61 m)	0.9 acres (0.4 ha)	100 feet by 100 feet (30.5 m by 30.5 m)	0.2 acre (0.1 ha)

Source: Ecology and Environment, Inc. 2005.

Note:

[a] ROW width for both the Center Road Pipeline and the Line 225 Pipeline Loop may vary depending on the roadway type.

Table 2.1-4 Land Requirements for Temporary Staging Areas During Construction of the Cabrillo Port Project

Facility	Installation/Construction	
	Dimensions	Area
Onshore		
Ormond Beach HDB staging area	250 feet by 325 feet (76 m by 99 m)	1.9 acres (0.75 ha)
Pipeline staging areas – Center Road Pipeline (per staging area)	400 feet by 600 feet (122 m by 183 m)	5.5 acres (2.2 ha) per staging area; 16.5 acres (6.7 ha) total
Pipeline staging areas – Line 225 Pipeline Loop (per staging area)	400 feet by 600 feet (122 m by 183 m)	5.5 acres (2.2 ha) per staging area; 11 acres (4.5 ha) total
Watercourse crossings – Line 225 Pipeline Loop: Santa Clara River	800 feet by 225 feet (244 m by 69 m)	4.1 acres (1.7 ha)
Watercourse crossings – Line 225 Pipeline Loop: South Fork Santa Clara River, San Francisquito Creek	375 feet by 225 feet (114 m by 69 m)	1.9 acres (0.8 ha) per crossing, 3.8 acres (1.5 ha) total

Source: Ecology and Environment, Inc. 2005.
Note: Proposed staging areas would not be located within any watercourse crossing.

codes. (See "Design Standards Applicable to Natural Gas Transmission Pipelines" in Appendix C3.) Vessels and containers used in the transport and storage of cryogenic liquids have been in use for several decades. Offshore facility mooring and subsea pipeline installation and operation have also been in use for many years for oil and gas production platforms, FPSO units, and vessels. There are currently more than 90 FPSO units in operation worldwide, including three that store liquid petroleum gas.

With respect to the proposed DWP design specifications, the USCG and MARAD require DWP applicants to provide preliminary design specifications as a part of the application that are detailed enough to assess potential impacts associated with a project; the CSLC has similar requirements for applicable lease applications. If an application were approved and a license issued, the Applicant would then be required to submit the final design for the offshore components to the USCG for approval. Also, if the CSLC approves the lease application, the lease would contain specific requirements for the submittal of detailed final design specifications for approval by State agencies. Both Federal and State approval of the final design would be required before construction can begin.

Final design specifications for the offshore pipelines and onshore facilities would also have to meet the same level of scrutiny. The agencies with authority over offshore pipeline design and safety are the U.S. Department of Transportation's (USDOT's) Pipeline and Hazardous Materials Safety Administration Office of Pipeline Safety (PHMSA-OPS), the CSLC, and the California Coastal Commission. PHMSA and the CPUC Division of Safety and Reliability have jurisdiction over onshore pipelines.

Applicable design and safety standards for this Project would be identified as part of a process, with significant input from the Applicant as well as input (and final determination) by the responsible Federal and State agencies. The Applicant would submit proposed design criteria to the agencies for review and comment. The Applicant would be expected to provide very clear criteria regarding the Project design basis, e.g., presumptions regarding the seismic zone or wind load exposure zone. The Applicant would also be expected to provide specific nationally and internationally recognized design codes, standards, and recommended practices that would be used for the analysis and design of each component of the Project, e.g., mooring lines, anchors, and risers. The Applicant would comply with any updated standards and conventions that are in place at the time of licensing.

The responsible agencies would review the proposed design criteria and may modify the criteria or require additional criteria to ensure that the Project would be designed, constructed, and operated safely, both offshore and onshore. The design criteria, as modified and approved by the responsible agencies, would be included as conditions of any license or lease granted to the Applicant.

None of the three lead agencies require DWP applicants to provide final detailed designs as part of their application. If an application is approved and MARAD issues a DWP license or a license with conditions, the DWP licensee is required to submit all plans of the offshore components comprising the DWP to the USCG for approval. If the CSLC approves the lease application, the conditions of the lease would include specific requirements for submittal of detailed design criteria and final detailed designs by the Applicant for review and approval by State agencies. Federal and State approval of final detailed design is required before construction can begin. (Key elements of the engineering process are described in AM PS-1a in Section 4.2.7.5, “Impacts Analysis and Mitigation.”)

The following steps would be taken to ensure that appropriate criteria would be used for the FSRU: (1) the USCG, in consultation with the CSLC, would assess the proposed criteria and standards for the design, construction, and operation in accordance with USCG Guidance for Oversight of Post-Licensing Activities Associated with Development of Deepwater Ports (USCG 2005); and (2) a third-party verification agent, likely a recognized classification society approved by the USCG in consultation with the CSLC, would evaluate and approve the proposed design and construction.[1] This is consistent with the Deepwater Port Act, which allows for flexibility in design while maintaining appropriate safety standards.

[1] A classification society (of which there are presently three) establishes and applies technical requirements for the design, construction, and survey of marine-related facilities, principally ships and offshore structures, and maintains research departments for the ongoing development of technical safety standards. Classification rules are developed to contribute to the structural strength and integrity of essential parts of the facility, such as a ship’s hull and its appendages, and to ensure the reliability and function of the power generation and other essential features and services. The owner of a ship that has been designed, built, and tested in accordance with the rules may apply for a certificate of classification indicating that the ship complies with the rules. Classification societies may also act as Recognized Organizations for Flag States.

Vessel Standards – Certificates of Class

The Applicant has stated that class certification will be obtained for all "vessels" associated with the proposed Project, including the FSRU and each of the LNG carriers. This means that the vessels will be designed and constructed in accordance with stringent requirements defined by an independent classification society. The certificates of class are based on rules published by the classification society that govern the design and construction of ships and offshore installations. A classification society has specific procedures regarding the level of design review and survey that are required to allow a vessel to be "classified." Classification would indicate that the vessel has met applicable class rules, international requirements, and specific national requirements. Also, some flag states delegate certain additional review and inspection responsibilities to classification societies.

The rules and regulations of the above entities are broad in scope, covering almost every aspect of a vessel's (and thus the FSRU's) construction, as well as operational standards. As the FSRU and carriers are designed to carry cryogenic gases, additional regulations would govern their construction. These International Maritime Organization (IMO) conventions include:

- Safety of Life at Sea (SOLAS), 1974/1981;
- Code for the Construction and Equipment of Ships Carrying Liquefied Gases in Bulk (Gas Carrier Code), 1983;
- International Code for Ships Carrying Liquefied Gases in Bulk (International Gas Carrier [IGC] Code), 1993;
- 1994/1996 Amendments to the IGC Code (replaced the Gas Carrier Code);
- International Convention on Standards of Training, Certification and Watchkeeping (STCW) for Seafarers, 1995;
- International Management Code for the Safe Operation of Ships and for Pollution Prevention (International Safety Management [ISM] Code) – adopted by IMO Resolution A.741 (18) in 1994;
- International Convention for the Prevention of Pollution from Ships, 1973 and Protocol of 1978 (MARPOL 73/78);
- International Regulations for the Prevention of Collisions at Sea 1972 (with latest amendments);
- International Association of Marine Aids to Navigation and Lighthouse Authorities publication NAVGUIDE; and
- The Society of International Gas Tankers and Terminal Operators (SIGTTO) training standards (currently in development).

Some of the major safety features required by the above entities would significantly reduce the likelihood of an accidental cargo release and would substantially mitigate any release, regardless of cause. These include requirements for double hull construction, separation of cargo holds and piping systems, accessibility for inspection, leak detectors in hold spaces, tank requirements for cargo containment, structural analysis, secondary containment and thermal management, tank construction and testing requirements, construction and testing requirements for piping and pressure vessels, emergency shutdown valves and automatic shutdown systems, loading arm emergency release couplings, pressure venting systems, vacuum protection systems, fire protection systems, and cargo tank instrumentation.

2.2 FSRU AND VICINITY

2.2.1 Properties of Natural Gas to be Imported to the Project

The Applicant anticipates importing high quality natural gas to the Project from Western Australia's Scarborough offshore gas field after it is developed and a liquefaction facility and terminal are constructed. The field, located on the Exmouth Plateau about 174 miles (280 km) off the western Australia coast in water about 2,953 feet (900 m) deep, reportedly contains about 8 trillion cubic feet (226.6 billion cubic meters [m^3]) of gas.

The gas would consist of approximately 99.5 percent methane, would contain very low carbon dioxide (0.34 percent) concentration, and is anticipated to meet California requirements for pipeline-quality gas throughout Project operations with no additional treatment (Alexander's Gas and Oil Corporation 2004). However, if Cabrillo Port were ready to begin accepting LNG before gas from the Scarborough field was available, the Applicant has stated that it would import natural gas that meets California requirements for pipeline-quality gas from other sources, such as Indonesia (Billiot 2004). In the unlikely event that the LNG carrier's cargo did not meet the required California specifications, the LNG carrier would not be allowed to offload its cargo at Cabrillo Port or in California and would be re-routed to an alternate terminal that could accept the LNG cargo, such as a terminal in Korea, Japan, or China.

The LNG would be sampled and analyzed for compliance with California pipeline-quality gas requirements twice at the source—once prior to loading onto the LNG carrier, and again during the loading operation. A "weathering" calculation would be conducted using laboratory analytical results to confirm that the cargo would comply with specifications after the "boil off" that would occur during the voyage. Once the LNG carrier is loaded, the analytical results would be transmitted to the FSRU. When the LNG carrier reaches California, the gas quality would be tested three additional times: (1) prior to receipt by the FSRU from the LNG carrier; (2) prior to transmission from the FSRU to shore; and (3) at the Reliant Energy Ormond Beach Metering Station by SoCalGas for recording chain-of-custody during transfer of ownership of the gas. The Applicant and SoCalGas would maintain records of gas quality at the FSRU and onshore respectively for a period of three years unless otherwise specified by regulatory or other requirements.

2.2.2 Floating Storage and Regasification Unit

The preliminary design of the FSRU, described below, would be finalized by the Applicant upon license approval and built to conform to International Maritime Organization standards. As discussed above, a third-party verification agent would certify the design.

2.2.2.1 Dimensions

The FSRU is classified as a manmade structure. The FSRU would be a ship-shaped, double-hulled facility with three spherical storage tanks (see Figure 2.2-1). The FSRU would be built specifically to transfer, store, and regasify LNG.

- The FSRU would measure approximately 971 feet (296 m) long, not including the mooring turret, and 213 feet (65 m) wide, and would displace approximately 190,000 deadweight tons.[2]
- The freeboard (the distance from the waterline to the deck) while loaded with LNG would be approximately 59 feet (18 m). The freeboard when the FSRU is ballasted, i.e., when the ballast tanks are completely full, would be approximately 62 feet (19 m).[3]
- The tops of the LNG storage tanks would be approximately 102 feet (31 m) above the main deck, placing them approximately 161 feet (49 m) above the waterline when loaded, and 164 feet (50 m) when ballasted.
- The cold stack height would be approximately 266 feet (81 m) above the waterline, or 105 feet (32 m) above the top of the LNG storage tanks, when loaded, and approximately 269 feet (82 m) above the waterline when ballasted.
- The diameter of the cold stack piping would be 4 to 8 inches (0.1 to 0.2 m).

2.2.2.2 Hull

Figure 2.2-2 presents an artist's rendering of the FSRU and Figure 2.2-3, on the same page, shows the berthing arrangement between the FSRU and an LNG carrier during offloading operations. The steel double hull would be designed with a bow and stern shape to minimize wave motion and provide a stable platform for operations. Ballast tanks would be located between the double hulls, while other tanks would be contained inside the inner hull. These inner tanks would store diesel fuel, lubricating oil, oily

[2] Dimensions have been rounded to the nearest foot and meter.

[3] When the FSRU is full of LNG, there would be no ballast and it would be at its "loaded draft." The loaded draft is the lowest in the water that the FSRU would ever be and is also its normal position relative to height above the water. As the FSRU converts LNG to gas, it would take on ballast water to compensate for the loss of LNG and would therefore maintain its loaded draft. Once the ballast tanks were full, any continuation of the regasification process would cause the FSRU to rise above the loaded draft. However, this would occur only if, for some reason, there were an extended delay in the arrival of the LNG carriers. Consequently, it is conceivable, though unlikely and rare, that the FSRU could float a maximum of 3 feet (1 m) higher than the loaded draft.

water, gray water (from sinks and showers), sanitary sewage, and potable water. The FSRU would be equipped with stern thrusters at the aft, or back end, of the hull for heading control only and would not contain engines or other propulsion systems; thus, it would not be able to get underway under its own power; however, the FSRU could use its positioning thrusters to maintain a controlled forward speed of a few knots in light weather conditions.

The hull of the FSRU would be painted Admiralty Pacific Gray or similar shade. The USCG would determine the final paint color and scheme for the FSRU hull based on navigational safety and other considerations.

Operations aboard the FSRU, including regasification, would occur 24 hours per day, 7 days per week. Berthing of LNG carriers next to the FSRU would only occur during daylight hours; however, the transfer of LNG from the carriers to the FSRU would occur at night. Other nighttime operations would be avoided where practicable, and lighting would only be used to ensure safety and security, and when operations require lighting. Lighting onboard the FSRU would be designed to minimize nighttime impacts. Movement sensors would be employed where practicable, and floodlight use would be minimized. Where used, floodlights would employ high efficiency, low glare fittings, such as sodium and metal halide types.

2.2.2.3 LNG Receiving, Storage, and Regasification Facilities

LNG Receiving Facilities

BHPB's DWP license application calls for a single berth and LNG receiving facility to be located on the starboard side of the FSRU initially, with an option to install similar facilities on the port side at a later date. The second berth, if added, would provide operational flexibility under unusual conditions and would never be used simultaneously because no more than one LNG carrier at a time would unload.[4] These facilities would consist of the on-deck loading arms, piping, and shutdown systems to allow safe transfer of LNG from the LNG carrier to the FSRU. Deck gear such as fenders, capstans (a type of winch for lifting heavy objects), and quick release hooks for the LNG carrier's mooring lines would also be located on the deck. Fenders would prevent contact between the hulls of the FSRU and the LNG carrier during berthing and transfer procedures.

All loading arms would be identical, with 16-inch (0.4 m) diameters. They would be located approximately midship along the starboard side of the FSRU. Three of the four loading arms would receive LNG, while the fourth would return natural gas vapor displaced from the FSRU back to the LNG carrier. A vapor return arm would be necessary because LNG, when transferred from one vessel to another, would cause the rising liquid (LNG) level in the FSRU receiving tanks to displace the volume available for the vapor already existing in these tanks (known as the piston effect). A vapor arm

[4] If added, the second berth would require a modification of the FSRU license and additional environmental documentation.

1 Insert (1 of 2)

Figure 2.2-1 Proposed FSRU Profile Schematic

Insert (2 of 2)

Figure 2.2-1 Proposed FSRU Profile Schematic

Insert (1 of 2)

Figure 2.2-2 Artist Rendering of FSRU

Figure 2.2-3 Artist Rendering of LNG Carrier Docked at FSRU During Offloading

Insert (2 of 2)

Figure 2.2-2 Artist Rendering of FSRU

Figure 2.2-3 Artist Rendering of LNG Carrier docked at FSRU During Offloading would also be necessary because the LNG being pumped into the receiving tanks would generate additional vapors in the receiving tanks due to the agitation of the liquid during pumping and due to contact between a cold liquid and the relatively warmer empty upper part of the receiving tanks.

The rising liquid level in the FSRU receiving tanks would push the vapor out through the vapor return line at a controlled rate and would be routed back to the source vessel's tanks to maintain balanced pressures. This "closed" cargo transfer arrangement would confine all of the vapor within the system. Thus, the atmospheres above the tanks' liquid levels would always be 100 percent natural gas and (since no oxygen is present) non-flammable.

The mooring and loading arm systems would have emergency quick-release capability so that LNG transfer could be safely stopped and the LNG carrier safely released even if timely weather warnings were not received, such as during a quickly developing squall or when encountering wave heights greater than the operational limitations as described in Sections 4.1.8.2, "General Wave Climate"; 4.1.8.3, "Extreme Wave Analysis"; and 4.1.8.4, "Operational Wave Conditions." When activated, the emergency quick-release actions would take less than one minute to complete.

The FSRU would receive LNG shipments two to three times per week on average, weather permitting, given standard operating procedure restrictions of significant wave heights of 9.2 feet (2.8 m). The LNG carriers would be resupplied and provided with logistical support by supply boats that would attend the LNG carrier while it is moored to the FSRU.

LNG carriers would have a capacity ranging from 36.5 to 55.5 million gallons (138,000 to 210,000 m^3). Of this volume, an estimated 4 million gallons (15,100 m^3) would be consumed by the carrier while in transit for fuel and for maintaining the cold tanks; the remaining 32.5 or 51.5 million gallons (123,000 or 195,000 m^3) would be transferred to the FSRU. LNG carriers would be powered by natural boil-off gas from their LNG cargo, as agreed with the U.S. Environmental Protection Agency (USEPA) (Klimczak 2005). The Applicant has not finalized design specifications for LNG carriers; therefore, the diesel storage capacity for LNG carriers cannot be estimated at this time.

The total LNG transfer rate through the starboard-side loading arms would be approximately 80,000 gallons per minute (gpm) (303 cubic meters per minute [m^3/m]), equivalent to 4.8 million gallons (18,200 m^3) per hour. The LNG carriers would be unloaded over a period of 16 to 22 hours, depending on the size of the LNG carrier. Berthing, unloading, and de-berthing would take approximately 18 to 24 hours (see Figure 2.2-3 for artist's rendering of berthing arrangement during offloading operations).

Loaded LNG carriers would not anchor under any circumstance, nor would they be any closer to the mainland than adjacent to the FSRU. One tug/supply vessel would be on standby all the time (24/7/365) in the vicinity of the 1,640-foot (500 m) safety zone surrounding the FSRU. A second tug/supply vessel would also be stationed in the vicinity of the FSRU except when making the weekly trips to Port Hueneme. If an LNG carrier were to become disabled while in U.S. waters, the tugboats would tow it out to sea where the LNG would be offloaded onto another carrier, and the disabled carrier would be emptied of gas prior to bringing it to a shipyard for repairs. The two tug/supply vessels would also be available and of sufficient power to intercept the FSRU in the unlikely event that it were to become unmoored.

The FSRU, LNG carriers, and tug/supply vessels would run their engineers on natural gas and a 1 percent biodiesel fuel pilot.

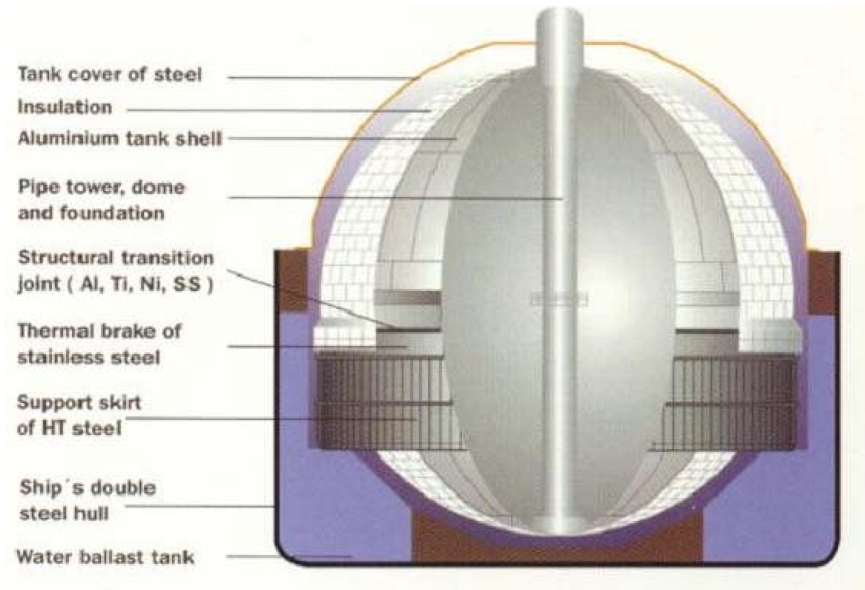
The inbound and outbound routes of the LNG carriers, agreed upon by the USCG and the U.S. Navy in consultation with the Applicant, are shown in Figure 4.3-1 in Section 4.3, “Marine Traffic.” These routes were deliberately selected to be away from areas transited by most other vessel traffic and would avoid the inshore traffic lanes.

If the supply of LNG to the FSRU were interrupted for an extended period of time, i.e., greater than three weeks, then, depending on the remaining level of LNG in the tank(s) and the ambient temperature, the three Moss tanks could be emptied during the regasification process, and there would be a small impact on operation of the FSRU. If the tanks were to become completely empty, they could warm up to ambient temperature by the time the LNG supply resumed, and up to 30 hours could be required to cool the tanks down before onloading of the LNG could occur. The cool-down of the tank(s) would involve slowly spraying a small quantity, i.e., several gallons, of LNG from the LNG carrier onto the interior walls of the tank(s). The Applicant has stated that it would take all steps necessary to prevent tank warm up by stopping the regasification process and ensuring that the tanks would always contain sufficient LNG to keep them cold (Hann 2005).

LNG Storage Facilities

The FSRU would store LNG in three Moss tanks. The Moss tanks would be located along the length of the facility, forward of the deckhouse/quarters and aft of the regasification equipment. A cross section of a Moss spherical tank is shown in Figure 2.2-4. Each Moss tank would be 184 feet (56 m) in diameter and would have an LNG storage capacity of 24 million gallons (90,800 m^3). The total LNG storage capacity on the FSRU would be approximately 72 million gallons (273,000 m^3).

Each Moss tank would consist of an aluminum internal tank shell surrounded by layers of insulating material and supported on a steel skirt ring that would be braced inside the double hull of the FSRU. After installation of each tank in the FSRU, a steel weather cover would be constructed over the top of the tank to totally enclose the structure and provide for a gas-tight hold space around the cargo tank. The covers would protect the tanks from exposure to potential ignition sources and provide protection to the crew quarters in the event of an accident. Each Moss tank would be located in a separate cargo hold and mounted directly on the foundation deck inside the double hull of the FSRU; this design would provide significant barriers to tank breach and escape of LNG.



Key: Al = Aluminum
Ti = Titanium
Ni = Nickel
SS= Stainless Steel
HT= High Tensile

Figure 2.2-4 Cross Section of Moss Tank

The normal tank operating pressure would be approximately 1 pound per square inch (psi) (700 kilograms per square meter [kg/m^2]) above atmospheric pressure; however, the tanks would be designed for overpressure to assist in cargo evacuation in the event of an emergency. Automatic relief valves would reduce tank pressure if it were to exceed 3.5 psi (2,460 kg/m^2) above the operating pressure. Discharge from the relief valve(s) would be to the atmosphere through a vent mast located at the top of each tank (also see “Emergency Depressurizing and Venting Systems” in Section 2.2.2.5, “Safety Systems”), and would consist of 95 percent methane.

The insulation on the FSRU’s Moss tanks would be designed to allow some liquid to warm over time and return to its gas form (a process called “boil off”). By maintaining fairly constant tank pressures through removal of this boil-off gas, the remaining liquid cargo would be maintained in its cold liquid form without mechanical assistance by a physical process called auto-refrigeration. About 0.12 percent of the LNG would be allowed to boil off each day under normal conditions. The boil-off gas would not be discharged but would be either used as a fuel supply for the electrical generators in the regasification process or diverted into the natural gas delivered to shore.

The Moss tanks would contain nine LNG pumps—three per Moss tank. Two of the each tank’s three pumps would be able to transfer up to 13,000 gpm (49 m^3/m) of LNG from the storage tanks to the booster pumps located in the regasification facilities area. The third pump would be used for tank cool down. The same transfer rate could be achieved with only two pumps, thereby allowing maintenance of pumps without interrupting LNG transfer.

LNG Regasification Facilities

The regasification facilities area, located on the bow (front) of the FSRU just forward of the storage facilities, would include up to six LNG centrifugal booster pumps and eight submerged combustion vaporizers. The booster pumps would increase the pressure of the LNG to approximately 1,500 pounds per square inch gauge (psig) (1.05 million kg/m^2) before feeding the LNG to the submerged combustion vaporizers (submerged in fresh water) where the LNG would be regasified. The LNG would be vaporized and would pass into the discharge manifold before being exported to shore via pipeline. This closed, high-pressure welded piping system would be designed and constructed to the required piping codes for high-pressure LNG service as listed in "Design and Safety Standards Applicable to Natural Gas Transmission Pipelines" in Appendix C3.

The eight submerged combustion vaporizers would each have a maximum LNG vaporizing capacity of 198 tons (179,600 kg) per hour. Any five of the eight submerged combustion vaporizers would operate at 80 percent load throughout the year. The burners on the submerged combustion vaporizers would be fueled by boil-off gas, and any boil-off gas not used for this purpose would be diverted back into the gas delivery system. The submerged combustion vaporizers would heat the LNG in a water bath, resulting in regasification of the LNG into natural gas at a temperature of 41°F (5°C). The LNG and natural gas flow would be contained within process piping submerged in a water bath maintained at 86°F (30°C). The water bath would provide stable heat transfer from the LNG to the natural gas, i.e., it would provide a heat source to convert the natural gas from a liquid to a gas. The regasification process is shown in Figure 2.2-5. The average regasification capacity would be 800 million cubic feet per day (MMcfd) (22.7 million m^3/day), and the maximum regasification capacity would be 1.5 billion cubic feet per day (42.5 million m^3/day). At a regasification rate of 800 MMcfd (22.7 m^3/day), it would take approximately 7 days for the Moss tanks to be emptied of LNG, or approximately 4 days at a regasification rate of 1.5 billion cubic feet per day (42.5 million m^3/day).

Natural gas combustion would heat the water bath used for regasification during the submerged combustion vaporizer process. No seawater would be used for the water bath. Fresh water for the water bath would be generated as a by-product of the combustion process in the submerged combustion vaporizer units, which would total 199,680 gallons (756 m^3) per day (based on an average of five submerged combustion vaporizers operating simultaneously). Each submerged combustion vaporizer would produce approximately 39,936 gallons (151 m^3) per day. Neither LNG nor natural gas would be released into the water bath, but combustion exhaust gas (mainly carbon dioxide and water vapor) would bubble through the water bath. The water in the bath consists of clean, distilled water; however, the bubbling of combustion gases through this water would cause the pH to drop, making the water slightly acidic. Therefore, any water discharged from the submerged combustion vaporizer operations would be treated to neutralize the pH for potable and non-potable use onboard.

This water would accumulate in the combustion vaporizer water bath. Approximately 5 percent of this volume, or 9,987 gallons (38 m^3) per day, would be treated using a combination of pH adjustment, ultraviolet light (UV) oxidation, and/or filtration through 1-micron filters and activated charcoal filters for use onboard the FSRU as deck washdown water, estimated at 63,400 gallons (240 m^3) per week during one eight-hour weekly event, or to supplement the desalination units for potable water use. The remaining 95 percent, or 189,748 gallons (718 m^3) per day, would be used for ballasting operations (described under "Ballast Water" below); therefore, no water would be directly discharged to the ocean from the vaporizer operations.

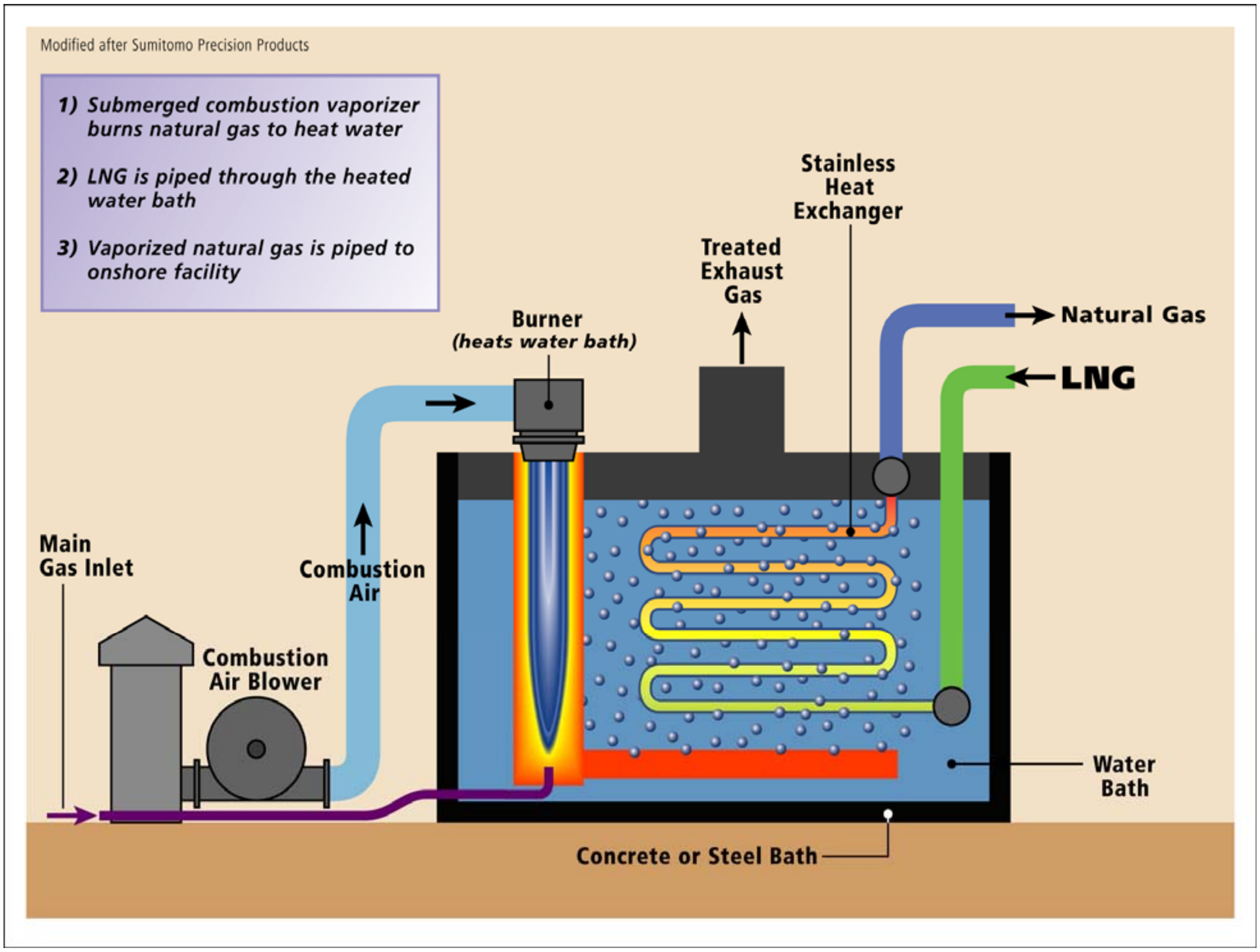


Figure 2.2-5 Submerged Combustion Vaporizer Process Schematic

Cold Stack

The plant would be equipped with a "cold stack," which would allow gas to be vented to the atmosphere. Venting would be allowed only in case of an emergency or abnormal process to vent the free gas in the plant piping or, in some incidents, to vent the volume of gas in the subsea pipeline. The amount of gas that would be vented during an emergency would depend on the severity of the situation. Under normal circumstances, no gas would be vented to the atmosphere. There would never be any flaring of the released gas, which would eliminate an ignition source aboard the FSRU. The vented gas would not be considered an asphyxiant for the FSRU crew because: (1) the gas is lighter than air and would therefore rise; and (2) the top of the cold stack would be the highest point on the vessel, well above the decks (see "Emergency Depressurizing and Venting Systems" in Section 2.2.2.5, "Safety Systems").

Natural Gas Metering

The two subsea pipelines running to shore would be fitted with independent flow meters at each end of the pipeline system (one onboard the FSRU and one onshore at the metering station). The meters would measure the flow through the individual pipelines and the cumulative flow through both pipelines such that if one meter were down the other would still measure the total flow.

2.2.2.4 Utilities Systems and Waste Management

Utilities on the FSRU would include electrical generation; heating, ventilation. and air conditioning; water and wastewater management; hazardous materials management; and garbage collection, storage, and transfer equipment.

Ballast Water

Ballast water would be managed through use of a computer-controlled ballast water management system during operation to maintain the vessel's draft and trim. The LNG carriers would come to the FSRU carrying some ballast water. According to international regulations, ballast water exchanges would occur outside the 200-NM (230 mile or 371 km) limit and would be recorded and reported.[5] While offloading their LNG cargo, the carriers would pump ballast water into their tanks to compensate for the weight of LNG discharged to the FSRU. Each LNG carrier would offload approximately 32.5 to 51.5 million gallons (123,000 to 195,000 m^3) of LNG, depending on the size of the LNG carrier; therefore, the minimum quantity of LNG to be received would range from 65 million gallons (246,000 m^3), the minimum volume for two carriers arriving at the FSRU per week, to 154.6 million gallons (585,000 m^3), the maximum volume for three carriers arriving at the FSRU per week. One gallon of LNG is equal to 0.4382 gallons of seawater. Therefore, the quantity of seawater required during offloading by each LNG carrier for ballasting would range from 14.2 to 22.6 million gallons (53,750 to 85,540 m^3), depending on the size of the carrier.

The FSRU would constantly exchange ballast water to maintain its draft and trim during both loading of LNG from LNG carriers and export of natural gas to shore using a computer-controlled ballast water management system, which is designed to constantly monitor load conditions and either intake or discharge seawater as necessary. During offloading operations from LNG carriers, the FSRU would discharge an amount of

[5] International Convention for the Control and Management of Ships Ballast Water & Sediments, U.N. International Maritime Organization.

ballast water equal to the amount of seawater taken in by the LNG carrier per shipment, or 14.2 to 22.6 million gallons (53,750 to 85,540 m^3), depending on the size of the carrier. Conversely, as the LNG is regasified aboard the FSRU and sent to the Ormond Beach Metering Station, a commensurate amount of seawater would be pumped into the ballast tanks.

The ballast water would be obtained from, and discharged to, the ocean in the same location adjacent to the FSRU. No chemicals would be added; therefore, treatment of the ballast water would not be necessary. Ocean water would be pumped into ballast tanks, shifted from one tank to another to keep the vessel evenly balanced, or discharged back to the ocean, as required. The exchange of ballast water would occur at the bottom of the FSRU's hull at a depth of approximately 42.7 feet (13 m). The ocean depth at the FSRU mooring location would be approximately 2,900 feet (884 m) and the keel, i.e., the part of the FSRU furthest below the waterline, would be approximately 43 feet (13 m); therefore, scouring of the ocean bottom could not occur. Ballast water pumps would be screened to minimize entrainment of aquatic organisms. Intake size and screen(s) would be designed in compliance with Clean Water Act § 316, as applicable. The ballast tanks would be inspected annually. Details of the ballast water system can be found in the Ballast Water System Operations and Design Features report (WorleyParsons 2005) in Appendix D5 of this report.

The Applicant investigated the feasibility of installing the ballast water pump intake on the ocean floor; however, this method was determined to be impractical from both an engineering and operational aspect. First, locating the intake on the sea floor would result in the uptake of large volumes of sand and other particulates that could damage the pumps, thereby requiring the use of screen that would have to be cleaned on a regular basis to prevent blockage of the intake system. Second, it is hydraulically difficult to lift the required volume of water over 2,600 feet (800 m). Third, this scenario would add power generation requirements and would therefore increase the emission of air pollutants.

All ballasting operations would be in accordance with the International Convention for the Prevention of Pollution from Ships (MARPOL), State, and USCG regulations and protocols.

Power Generation

A utility area near the stern (back) of the FSRU would include the onboard electric power generation equipment. This primary power generation equipment would consist of four dual fuel (natural gas and diesel fuel) generators, each with a power output of 8,250 kilowatts at 6.6 kilovolts, that would normally operate using natural gas (boil-off gas from the Moss tanks and/or the natural gas that has been regasified on the FSRU). In addition, one emergency backup generator using diesel fuel would be onboard for emergency use only. The dual fuel generators would operate using diesel fuel only under the following conditions: (1) for emergency fuel if both sources of natural gas were lost; (2) for monthly tests of the emergency generator and firefighting water pumps and occasional tests of the dual fuel generator; (3) during emergency training drills; or (4) during commissioning before the first delivery of LNG.

The four generator engines would use a closed circuit cooling water system with a total fresh water capacity of 396 gallons (1.5 m^3) per engine. Each engine would have two cooling circuits. A small amount, approximately 10 percent, of make-up water would be required per year and would be obtained from the submerged combustion vaporizers. Therefore, fresh water consumption would total about 300 gallons (1.1 m^3) annually. The anti-fouling inhibitors would be a generic glycol-based product as specified by vendor specifications. The closed circuit cooling water system would employ non-contact seawater for heat transfer in an average amount estimated at 142,000 gallons (535 m^3) per hour when the generators are in operation. Under normal operating conditions, the FSRU seawater cooling water intake would be about 10 percent of that for typical large oceangoing ships. The Applicant considered the use of a heat recovery system using the submerged combustion vaporizer-generated water to cool the generator engines; however, this option was rejected because of the disadvantages of such a system with respect to increased system complexity.

All the required motor control centers, substations, cabling, and lighting systems would be arranged in accordance with applicable regulations and standards regarding protection, insulation, and general safety as listed in "Design and Safety Standards Applicable to Natural Gas Transmission Pipelines" in Appendix C3. All electrical equipment within hazardous zones would be designed, installed, and supplied with certificates to show that the equipment is intrinsically protected or explosion-proof.

Fuel Gas

As previously stated, the Moss tanks would allow natural gas boil-off of 0.12 percent per day. The boiled off natural gas would be compressed and injected into the subsea pipelines and transmitted to shore or recovered and used on the FSRU. The boil-off gas compressor plant would require four compressors. Boil-off gas from vaporization of LNG would be used as the primary source of fuel for the FSRU and would fuel the main generator engines and the submerged combustion vaporizers (Figure 2.2-5 above). Because the quantity of boil-off gas would typically be insufficient to supply the FSRU, gas would also be taken from the vaporizer discharge header and used as fuel for the power generation equipment.

Diesel Fuel

The FSRU would be loaded with 264,000 gallons (1,000 m^3) of diesel fuel before departing from the fabrication shipyard. The storage tank would be located on Deck 4 in the aft engine room within a separate room located away from sources of heat and ignition and enclosed by steel bulkheads and walls extending from floor to ceiling, in compliance with applicable ship codes and rules. The fuel would be used for initial power generation during installation and commissioning until receipt of LNG. One small day tank would supply the four dual fuel generators, and another would supply the emergency backup generator. The day tanks would be located on Decks 2 and 3 in the aft engine room within the double skin main hull of the FSRU. Each tank would be accessible from all outer sides to allow inspection. Secondary containment would consist of drip trays with extended walls under each tank and associated equipment, e.g., day tanks on the generators that would collect any leaks from valves and fittings and flow to a drain tank.

The diesel fuel supply would be replenished by transporting approximately 350-gallon (1.3 m^3) capacity containers to the FSRU on the supply vessels as needed. (BHPB estimates one trip will be needed per month.) The containers would be offloaded from the supply vessel and placed in a bermed area on the deck of the FSRU, where the diesel would be gravity fed into the storage tanks. Empty containers would be returned to shore via the supply vessel for reuse.

Storm and Bilge Water

When it rains, an estimated 30 gallons (0.1 m^3) per minute would flow onto the entire surface of the FSRU. To prevent the FSRU from becoming unstable, all rainwater and deck washdown water would be allowed to flow off the FSRU unimpeded, except in areas where it could become contaminated with oil. Rainwater or deck washdown water that collects within secondary containment areas would be stored in tanks to be monitored for oil content. If determined to be clean, this water would be discharged directly to the ocean; otherwise, it would be processed through an oil/water separator before discharge to the ocean. Bilge water, i.e., the water that collects in the bottom of a ship as a result of leaks through propeller shafts, etc., is not anticipated to accumulate in the FSRU because it would not have a propulsion system. Some water may collect, however, from leaks in the seawater cooling systems. Although any bilge water would be anticipated to be clean, it would be pumped through the oil/water separator prior to discharge to the ocean. The volume of bilge water is estimated to be 240,000 gallons (910 m^3) per year. Oil collected in the oil/water separator would be placed in drums for subsequent disposal at an onshore licensed hazardous waste disposal in accordance with Federal, State, and local regulations.

Hazardous Materials and Lubricants Management

Materials that are classified as hazardous and that would be used onboard the FSRU during normal operations include natural gas odorant, paints, fuels, solvents, urea, and caustic. In addition, lubrication oil would be stored onboard for use with various mechanical equipment such as generators, pumps, compressors, and deck winches and cranes (see also Section 4.12, "Hazardous Materials"). The estimated inventory of lubricants to be stored on the FSRU during operation is 70 m^3 of lube oil (50 m^3 in lube oil tanks or sumps), 3 m^3 of hydraulic oil; 1 m^3 of glycol/water; and 2.50 kg of grease (BHPB 2004).

Natural Gas Odorization

All natural gas supplies, including those provided by SoCalGas, must be odorized to aid in the detection of leaks by smell. In response to public concerns about unodorized natural gas flowing from the FSRU to shore and across the beach, the Applicant would inject odorant into the natural gas stream at the FSRU. (SoCalGas would also manage a backup odorant system onshore.) The odorant, a flammable liquid with a sulfurous odor, would be added on the FSRU after the LNG is regasified. The odorant liquid would be injected at a rate of 0.4 pounds per million cubic feet of natural gas, or 320 pounds (42.3 gallons [0.16 m^3]) per day at the average LNG regasification rate of 800 million cubic feet (22.7 million m^3) per day.

Odorization on the FSRU would involve the use of 1,000-liter containers of odorant, one every four days for two weeks of operation, or a total of 4,000 liters stored onboard.

The injection equipment, to be located in the regasification portion of the FSRU, would consist of four bulk tank containers, two per gas stream, to provide flexibility and security of supply. The tanks would be placed within secondary containment areas having a capacity of 110 percent of the storage tanks to contain spills and leaks. Empty tanks would be replaced with full tanks to minimize risks, such as spills and personnel exposure, associated with transfer of the material from one container to another. The containers would be secured in place within the secondary containment area using locking shoes/chocks. Hose connector couplings would be self-sealing in the disconnect mode to prevent leakage from the hose.

The mercaptan gas would be SpotLeak 1039, a 50/50 mixture of tert-Butylmercaptan (CAS 75-66-1) and Tetrahydrothiophene (CAS 110-01-0) manufactured by ATOFINA Chemicals, Inc. Because SpotLeak 1039 is a flammable liquid with a flash point of 50° Fahrenheit (F) (10° Celsius [C]), the storage/injection station would be sited away from any ignition sources, and appropriate fire protection, e.g., deluge and/or foam, would be kept on board. Also, SpotLeak does not dissolve in water and will float on the water surface; therefore, adequate personal protective equipment and absorbents would be on site as required for handling and spill mitigation. The area in and around the odorant storage/injection stations would be monitored using explosimeters and infrared gas detectors capable of detecting both odorant and natural gas leaks.

Paints and Solvents

FSRU maintenance activities would require the use of various paints, solvents, and other hazardous materials. These materials would be brought onboard in retail-size containers and stored in designated compartments specially designed and constructed for the storage of hazardous materials and paints. Empty containers would be hauled to shore for appropriate recycling or disposal.

Urea

The power generation equipment aboard the FSRU would be equipped with air emissions control equipment designed to reduce the emission of nitrogen oxides. Urea would be used in this process instead of aqueous or anhydrous ammonia because it is considered safer. The Material Safety Data Sheet for these materials identifies ammonia as having a "severe" health and contact rating, while urea is considered "moderate." Also, urea is considered a skin irritant while ammonia can cause caustic burns. The urea would be transported to the FSRU and stored as bagged solid pellets and mixed into an aqueous solution onboard and stored in dedicated tanks. The use of dry urea would reduce the inherent risk of handling aqueous or anhydrous ammonia in an offshore marine environment.

Lubricating Oils

The onboard mechanical equipment, including power generation units, boil-off gas compressors, fire-fighting water deluge system pumps, and ballast water pumps, would require holding an inventory of lubricating oil as periodic change-out of lubricating oil is necessary. Replacement oil would be brought onboard in 55-gallon (0.2 m^3) drums or 350-gallon (1.3 m^3) totes. Used oil would be returned to shore in the same containers used to provide the replacement oil. Used oil would be managed, disposed of, or recycled in accordance with the USEPA and State requirements. All oil would be managed in accordance with the facility-specific Spill Prevention, Control, and Countermeasures (SPCC) Plan (see Section 4.12, "Hazardous Materials").

2.2.2.5 Safety Systems

The FSRU would carry emergency systems and equipment for hazard detection, emergency shutdown, spill containment, fire protection, flooding control, crew escape, and all other such systems and equipment required by the USCG and other applicable regulatory agencies. Safety systems would also include crew safety shelters located on the forward part of the FSRU and in the crew accommodation area, dedicated fire system pumps, unobstructed walkways, and life rafts.

The regasification facility aboard the FSRU would be highly instrumented and monitored/controlled from the central control room located in the deckhouse. The regasification facility would be protected by extensive safety systems, including fire and gas detection, fire-fighting systems, a shutdown system, and a blowdown system. Blowdown is a means of providing controlled venting, or emptying, of the contents of a pressurized pipeline to perform inspections, maintenance, or repairs. Blowdown systems are located on both the upstream and downstream sides of the mainline valves, which are used to isolate segments of a pipeline.

The integrity of the regasification facility would be ensured through a formal and documented inspection and maintenance program. Vessels, pumps, piping, and instruments would be inspected and maintained at regular intervals, which would be specified at the final design stage of the FSRU. All maintenance operations would be performed under strict guidelines designed to minimize releases and to ensure the safety of the system and personnel.

Hazard Detection and Emergency Shutdown Systems

The FSRU would be equipped and designed to provide a high level of protection to personnel, the unit itself, and the environment against the effects of an uncontrolled release of hydrocarbons or other process gases. For example, the FSRU would be designed to separate the process area from the crew accommodation area. Likewise, the Moss tanks, mooring, and risers would be separate from the process area. The outer shell of the forward tank (adjacent to the process area) would be fitted with a special barrier as part of the tank's weather cover to provide enhanced protection against fires or other potentially dangerous process area incidents.

Emergency Shutdown

The facility, including the FSRU, offshore pipelines, and berthed LNG carrier, would be protected by comprehensive emergency shutdown systems. These would be electronic, high integrity, redundant systems that would initiate a range of shutdown actions, with the course of action depending on the nature and severity of the cause for shutdown. The type of shutdown system would include electronic detection devices, thermal fusible plugs, and pneumatic pipe loops, which would automatically activate a range of shutdown procedures keyed to the cause for the shutdown. Manually activated shutdown initiators at various locations, including the facility's control room and crew safety shelters, would complement these.

Fire and gas detection devices would be located at strategic locations throughout the facility, including the Moss tank domes, loading arm areas, and the regasification facility. The status of the fire and gas system would be reported on a monitoring panel, and the integrity of the complete system would be maintained by frequent and regular testing.

Emergency shutdown comprises multiple levels of action from individual equipment shutdown to shutdown of a system or area to an overall facility shutdown. Where appropriate, the shutdown systems would initiate loading arm and mooring line release mechanisms, which would initiate the departure of the LNG carrier.

Emergency Depressurizing and Venting System

The FSRU would be equipped with a cold stack to vent natural gas vapors in the event of an emergency. The cold stack would be provided with an electric heating system to vaporize any emergency LNG releases and, if used, would discharge natural gas to the atmosphere. The cold stack height would be approximately 266 feet (81 m) above the loaded draft waterline (269 feet [82 m] if the FSRU were empty) and approximately 105 feet (32 m) above the top of the storage tanks, elevated personnel walkway, and elevated piping along the tops of the tanks. These specifications would allow dispersal of the natural gas, considering the presence of the FSRU and an adjacent LNG carrier.

Two additional vent systems would be provided: one high-pressure vapor system that would handle releases from the LNG vaporizers and the high-pressure boil-off gas compressor, and a low pressure vent that would handle low pressure gas releases and liquid discharges from thermal relief valves and equipment drains. Any small liquid discharges would be caught in the low-pressure vent knock-out drum, where it would be regasified using an electric heater. The natural gas would then be vented through the stack, with further electrical heating, if necessary, to ensure proper dispersal to the atmosphere. In the event of an emergency, processing operations would be shut down and the electric heater would be kept running through the use of the emergency generator. (Power and emergency generation is discussed further in Section 2.2.2.4, "Utilities Systems and Waste Management.") The vent outlet would be elevated to the top of a vent stack to ensure adequate dispersion of vapors below the flammable concentration limit (see Section 4.2, "Public Safety: Hazards and Risk Analysis"). As previously stated, no gas would ever be flared.

Emergency Response

All vessels, facilities, and operational activities conducted by the Applicant would be covered by emergency response plans, which would address specific incidents, e.g., oil spills, fires, collisions, and other identified potential incidents (BHPB 2004). The plans, e.g., Draft Facility Oil Pollution Contingency Plan, Cabrillo Port LNG Terminal (BHPB 2004), would be discussed with and approved by Federal, State, and local authorities, as required by law. The Applicant would provide personnel training to both its own employees and contractor personnel involved in the LNG and support operations, including the FSRU crew, LNG carrier crew, and tug/supply vessel crew. Periodic drills and emergency exercises would be conducted both internally, for Applicant and contractor personnel, and externally, for organizations and regulatory authorities that might be involved in emergency response activities associated with LNG operations.

The initial response to any emergency at the FSRU would be carried out by personnel aboard the FSRU and dedicated support vessels. The FSRU and support vessel personnel would be trained to respond to all identified emergencies and would be provided with the necessary equipment and outside support to respond according to the above plans. The Applicant would also contract with trained and experienced emergency response contractors and service providers.

The Applicant's Incident Management Team, organized in the Federal and State recognized Incident Command System, would support the offshore emergency responders and coordinate with Federal, State, and local emergency management personnel. The USCG would be the lead agency to respond to any public safety emergency and would coordinate efforts of other Federal, State, and local agencies. For more information on emergency response, see Section 4.2, "Public Safety: Hazards and Risk Analysis."

Gas Detection Systems

The FSRU would be equipped with a stationary gas detection system consisting of continuously operating catalytic type detectors and infrared line-of-sight detectors connected to the FSRU's electronic fire and gas panel. The gas detection system would sound audible alarms as well as initiate the shutdown of appropriate equipment and systems. Gas detection would also be provided for the regasification plant, other deck areas such as the Moss tank domes and loading arm areas, machinery spaces through which high pressure gas is piped, and the ventilation air inlets to safe spaces, including personnel accommodation areas.

Fire Protection Systems

Different firefighting systems would be used, depending upon the location and type of fire. These would include a main seawater deluge system to contain a gas fire and to avoid ignition in case of gas releases; a dry chemical powder system for LNG fires; a low expansion foam system for process deck areas, machinery and oil storage spaces; a carbon dioxide fire suppression system for machinery spaces, paint lockers, and all flammable materials storage areas; and a conventional sprinkler system for living quarters plus supplemental fire extinguishers stationed at multiple locations around the FSRU.

The main firefighting system would be tested annually with seawater. The volume of seawater to be used and discharged during testing of the main system would be approximately 105,680 gallons (400 m^3) per year. Following completion of the test, the system would be flushed with an equal volume of fresh water generated by the submerged combustion vaporizers. The seawater intakes for the firefighting system would be designed to be the same as those for the ballast water system. These are discussed under Impact BioMar-3 in Section 4.7 “Biological Resources – Marine.”

The total firefighting water demand for the FSRU, in the event of an actual fire, is estimated to be 634,000 gallons (2,400 m^3) per hour. Four firefighting water pumps would be installed, each of which would be tested monthly (one pump each week) for approximately 15 minutes. Each pump test would require 5,725 gpm (21.7 m^3/m), or 85,875 gallons (325 m^3) per test. Consequently, the volume of seawater required for testing the firefighting water pumps would be 4.12 million gallons (15,600 m^3) per year.

The 25 deluge valves would also be tested monthly using 1,982 gallons (7.5 m^3) per valve per test using fresh water generated onboard from the submerged combustion vaporizers during the regasification process. The deluge valves would be tested using a jockey pump through a 2-inch (0.05 m) diameter bypass line. Each deluge valve test is assumed to take five minutes utilizing 1,982 gallons (7.5 m^3) of fresh water for an annual consumption of 594,450 gallons (2,250 m^3) per year. The deluge valves would also be flushed with fresh water after the annual seawater test, which would require an additional volume of 105,680 gallons (400 m^3).

Spill Containment System

Secondary containment would be designed for areas with the greatest risk of LNG release, such as the loading arm area, and would have two main functions: (1) to safely contain any releases from the primary containment (tanks and loading manifold area); and (2) to safely protect the FSRU from potential damage from exposure to cryogenic temperatures. Spill containment would be designed in accordance with the codes and standards applicable to LNG carriers and terminals, including a SPCC Plan, as required for Deepwater Ports under 40 Code of Federal Regulations (CFR) Part 112.1(a).

Natural Gas Purging with Inert Gas

The use of nitrogen and/or other inert gas to purge areas that may have undesired concentrations of natural gas is a standard industry safety procedure. Nitrogen would be used when necessary to purge natural gas from FSRU gas-related equipment. The process prevents the introduction of air that, when mixed with residual natural gas, could result in a mixture within flammable limits. Nitrogen would be generated onboard the FSRU using a process that separates nitrogen from the ambient air.

2.2.2.6 Other Operations

Equipment, Supplies, and Personnel Transfer Area

The FSRU would have an operations crew of about 30 persons that would be rotated every seven days and transferred by supply vessel from Port Hueneme. The Applicant estimates that once a week, one tug/supply vessel would make the round-trip transit between the FSRU and Port Hueneme, resulting in approximately 52 round-trip transits per year for crew changes and supply runs. These trips would be made during daylight hours. Incoming supplies and outgoing wastes would be transferred by supply boat. Solid supplies could include food, toiletries, office supplies, tools, spare parts, dry chemicals, and other maintenance and repair materials. Outgoing wastes from the FSRU that could not be discharged pursuant to the facility-specific National Pollutant Discharge Elimination System (NPDES) permit issued by the USEPA would be containerized for transfer to the supply vessel. In addition, a small, fast crew boat, based in Port Hueneme, would be available to travel to the FSRU during daylight hours to bring provisions and to transport LNG carrier crews when necessary.

A crane and basket at the stern (back) of the FSRU would transfer supplies, parts, other needed items, and personnel to and from the FSRU and supply vessels and offload garbage, waste oil and other hazardous wastes, and other items as needed for disposal on shore. A large floating fender would be deployed from the stern to prevent damage to the FSRU and the supply boats.

Helicopter Landing Area

A helicopter landing area would be located on the stern of the FSRU, above and behind the deckhouse. This pad is intended for limited use (mainly for visitors and during emergencies). No aircraft fuel or refueling facilities would be located onboard the FSRU.

Deckhouse

Located behind the Moss tanks and just forward of the helicopter landing area on the stern of the FSRU, the deckhouse would have facilities to accommodate a crew of up to 50, although a permanent crew of 30 would typically occupy the FSRU. For safety reasons, all living, dining, and recreation spaces would be contained in this deckhouse to separate the processing area from the crew area.

Command and control facilities, including monitoring and control instrumentation for LNG/natural gas process activities, ballast system, communications, radar equipment, electrical generation, emergency systems, and thruster controls, would be located in a central control room in the deckhouse. A command bridge space, located at the top of the deckhouse above the crew accommodations, would serve as a backup location for the command and control functions and would be primarily used during docking/undocking and other marine traffic-related operations.

Potable Water

The Applicant would use two seawater desalination units powered by waste heat recovery from the power generator engines to produce potable water. Each unit would produce 132 gallons (0.5 m^3) per hour of fresh water from a seawater throughput of 370 gallons (1.4 m^3) per hour (assuming 70 percent efficiency). The brine discharge from the unit to the ocean would be approximately 5,429 gallons (20.5 m^3) per day or 1,981,600 gallons (7,500 m^3) per year. The brine would be discharged in accordance with a facility-specific NPDES permit issued by the USEPA.

The Applicant also plans to use some water from the submerged combustion vaporizer units to supplement desalination. This additional water would be treated using a UV oxidation unit, then filtered through a 1-micron filter, and finally filtered through an activated charcoal filter for potable water use. This method would avoid the need for storing or using chlorine gas or sodium hypochlorite on board the FSRU to treat the water to drinking standards.

Wastewater Treatment and Discharge

Gray water (from showers and sinks) would be collected for onboard treatment. Assuming that each of the permanent crew of 30 personnel used approximately 90 gallons (0.34 m^3) per day, the total volume of gray water would be approximately 2,700 gallons (10.2 m^3) per day or 985,500 gallons (3,730 m^3) annually. The gray water would be treated using filtration to separate particulate matter and UV oxidation to destroy dissolved organic materials. Discharge of treated gray water to the ocean would be in accordance with a facility-specific NPDES permit issued by the USEPA. Black water (sanitary wastes) from the FSRU, estimated at approximately 90 gallons (0.3 m^3) per day or 32,850 gallons (124 m^3) annually, would also be treated aboard the FSRU using a USCG certified Type II Marine Sanitation Device, with the treated liquid portion discharged to the ocean in accordance with the FSRU's NPDES permit. The generated sludge would be containerized for subsequent transfer to shore for disposal at a local wastewater treatment facility once every three months.

2.2.3 Mooring and LNG Transfer

The FSRU would attach to nine anchor cables and four gas risers at its pivot point on the bow (see Figure 2.2-2 above). This structure, a turret-style mooring point, would allow the FSRU to weathervane, or rotate 360°, depending on wind and wave conditions or use of the stern thrusters. The mooring point would serve two purposes: to hold the

FSRU in position through the anchor cables and to connect the flexible natural gas risers to the vessel for the export of natural gas to shore via pipeline.

2.2.3.1 Mooring System

The mooring position would be fixed using the nine cables and associated anchor points. The cables and anchor points would be arranged in three groups of three, separated from each other by 120° angles. The anchor cables would spread out from the mooring location to anchors located on the seafloor approximately 2,900 feet (884 m) below the water surface at a radial distance of approximately 0.75 miles (1.2 km). The ocean floor anchor points would be drag-in type anchors.

2.2.3.2 Flexible Risers and Riser Pipeline End Terminations

The natural gas would flow through the turret mooring point and into the four 11-inch (0.3 m) diameter flexible risers that would extend from the mooring turret to the pipeline end terminations (PLETs), which in turn would be connected to the pipeline-ending manifold (PLEM), i.e., the entry way connecting the two subsea pipelines running to shore. Each riser would be anchored to the sea floor but would have sufficient flexibility to allow the mooring turret to move within the design range.

The flexible risers, while having all the pressure containment characteristics of equivalent steel pipe, would also have sufficient flexibility, length, and strength to allow the FSRU to move on its mooring system, even under extreme conditions, without risk of damage. The risers would be designed to withstand both maximum design operating pressure as well as 100-year storm conditions, even with one mooring cable broken.

The flexible risers would be equipped with redundant shutdown valves on each end. The mooring point end of each riser would have two valves in series: an isolation valve and an automated safety shutdown valve.[6] Cross-connections between the four risers would also have isolation valves. The cross-connections would tie in to each riser between the isolation valve and the shutdown valve. Similarly, the termination of the flexible risers at the sea floor would include shutdown valves and cross-connections. Any individual riser could be shut down and isolated for inspection, maintenance, or repair while natural gas transmission continued in the other three.

2.2.3.3 Pipeline End Manifold

The four flexible risers would interconnect to the subsea transmission pipelines via the PLETs through the prefabricated, skid-mounted PLEM anchored on the sea floor. The PLETs would be located on the sea floor at a radius of approximately 558 feet (170 m) from the centerline of the mooring turret. The flexible risers would connect directly from

[6] A shutdown valve can be automatically shut down by the safety shutdown systems if an abnormal or dangerous condition is detected, whereas an isolation valve requires deliberate human intervention to open or close.

the FSRU, via the PLETs, to the PLEM. The PLEM would in turn be connected to the subsea pipelines through two steel pipes.

Each riser connection to the PLEM would be equipped with one shutdown valve and one isolation valve mounted in series on the PLEM that would normally be operated from the surface but that could be operated by a remotely operated vehicle as a backup. The PLEM would also contain two 24-inch (0.6 m) diameter shutdown valves in series at the tie-in for the subsea transmission pipelines. All subsea safety shutdown valves would be hydraulically operated from the FSRU. All shutdown valves, no matter their locations, would be subject to automatic action and shutdown by the emergency shutdown system located on the FSRU. This system would take appropriate action if sensors detected abnormal or dangerous conditions, e.g., a significant drop in pressure indicating a leak in the pipeline. All subsea shutdown valves would be designed to close if there were a failure in the pipeline system between the FSRU and the onshore metering station. In the event of loss of the hydraulic control cable, the affected shutdown valve would close and natural gas flow would be stopped.

2.2.4 Safety Zone and Area to be Avoided

Under Federal law (33 CFR Part 165.2 Subpart C, “Safety Zones”), a safety zone is an area “to which, for safety or environmental purposes, access is limited to authorized persons, vehicles, or vessels. It may be stationary and described by fixed limits or it may be described as a zone around a vessel in motion.” As stated previously, because the stern of the FSRU would be capable of rotating 360° around the mooring point, the USCG proposes to measure the safety zone around the stern of the FSRU rather than from the fixed turret mooring location at the bow of the FSRU, as originally described in the October 2004 Draft EIS/EIR. This safety zone would remain the same when an LNG carrier were moored next to the FSRU and during offloading operations.

According to the United Nations Convention on the Law of the Sea and the Continental Shelf Act of 1964 (No. 28 of 3 November 1964, as amended by the Continental Shelf Act Amendment Act, No. 17 of 14 November 1977), a safety zone can only extend to 0.27 NM (0.3 mile or 0.5 km) as “measured from each point of the outer edge of the installation or device, around any such installations or devices in, on, or above the continental shelf.” Several outer continental shelf platforms off California have 0.27 NM (0.3 mile or 0.5 km) safety zones established pursuant to 33 CFR Part 147 (see Section 4.3.2, “Regulatory Setting” in Section 4.3, “Marine Traffic”).

In accordance with 33 CFR Part 165, the Assistant Commandant for Marine Safety, Security, and Environmental Protection would establish the safety zone by publishing a Federal Register notice. The District Commander or the Captain of the Port would also present a formal description of the safety zone to the National Oceanic and Atmospheric Administration (NOAA), including the coordinates, in accordance with the North American Datum of 1983. In addition to establishing safety zones, the USCG is authorized to request from the IMO establishment of routing measures for ships under the 1974 Safety of Life at Sea Convention, including “areas to be avoided.”

The Area to be Avoided (ATBA) would likely extend to 2 NM (2.3 miles or 3.7 km) from the stern of the FSRU; however, the actual size of the ATBA would be established through the advice and consent of the Office of Vessel Traffic Management (OVTM) of the USCG. The ATBA is considered by the USCG to be a routing measure. The OVTM would evaluate the size of the ATBA based on location, port configuration, and size of the LNG carriers to be serviced. The OVTM would likely consult with USCG district-level waterways management staff to ensure that all geographic factors are considered before determining the final routing measures. The needs and desires of the operator would factor into the final decision, but a private entity cannot intrude on an established shipping lane available to all vessel operators (public, commercial, and recreational vessels). Routing measures would be appropriately configured.

The USCG would submit a written request to the IMO to establish the ATBA, and the IMO would present the request to its Maritime Navigation Safety Committee. If approved, the ATBA would be implemented approximately one year from the time of submittal and would appear thereafter on maritime charts published by IMO member nations, including those charts published by NOAA. Until the new charts are published, Notices to Mariners, which are published weekly by the USCG District Aids to Navigation staffs and monthly by NOAA, would direct mariners to make "pen and ink" changes to their existing charts.

2.3 OFFSHORE PIPELINES AND SHORE CROSSING

2.3.1 Offshore Pipelines and Associated Facilities

The Project would include two parallel 24-inch (0.6 m) diameter subsea gas transmission pipelines to deliver the natural gas from the FSRU to a new onshore interconnect. The onshore interconnect and other onshore facilities would be financed by the Applicant but constructed, owned, and operated by SoCalGas. The total length of the pipelines from the PLEM at the FSRU to the SoCalGas main line valve would be approximately 22.77 statute miles[7] (36.64 km). The Applicant's initial proposal to install one 30-inch (0.76 m) diameter offshore gas pipeline was modified to two 24-inch (0.6 m) diameter pipelines to provide redundancy during inspection or maintenance (natural gas can flow through one pipeline while the other one is being serviced) and to reflect the capability of most pipelaying barges, which handle steel pipe up to 24 inches (0.6 m) in diameter.

The proposed offshore pipeline route has changed from the route identified in the October 2004 Draft EIS/EIR. The proposed route was selected for the offshore pipelines after conducting a seismic design analysis and review to reduce the effects of potential turbidity flows over the lower section of the pipelines. The pipelines would run parallel to the seafloor slope along a relatively broad ridge and two shallow troughs to minimize the potential of turbidity flow effects. The proposed route of the offshore

[7] For consistency with the application and onshore pipelines, the length of the offshore pipelines is expressed in statute miles throughout this document.

pipelines is now shorter, i.e., 22.77 miles (36.64 km) instead of 24.8 miles (39.9 km) in the October 2004 document.

The subsea transmission pipelines would originate from the PLEM on the ocean floor below the FSRU mooring point and extend to shore. The twin pipelines would be laid on the seafloor approximately 100 feet (30.5 m) apart, in waters deeper than 43 feet (13 m), as suggested by the U.S. Department of the Interior, Minerals Management Service (MMS). These depths occur approximately 3,000 feet (0.6 miles or 0.9 km) offshore. The near-shore length of the pipelines would be buried (see Section 2.3.2, “Shore Crossing”).

The subsea pipelines would cross three telecommunication cable crossings en route: the Navy RELI cable, the Navy FOCUS cable, and the Global West cable. Both of the Navy cables are buried beneath the seabed. Although the Global West EIR had indicated that the cable would be buried, it is laid on the sea floor but has never been used. These cables would be crossed using sandbags, concrete mats, or “sleepers” (fabricated steel pipe supports). The Applicant and the Navy would execute a Memorandum of Agreement addressing the offshore pipeline crossing of the Navy underwater cables prior to construction of the pipeline. Global West is in bankruptcy and its receiver has not responded to communications from BHPB.

The twin pipelines would be made of carbon steel and coated on the outside with an anti-corrosion coating. In addition, sections of the pipeline would be concrete-coated, as necessary, to prevent waves from moving the pipeline. Aluminum anode rings (called "bracelets") would be attached at regular spacing along the pipeline to provide cathodic corrosion protection. Finally, in areas where necessary, based on local conditions, stiffening ring elements (called "buckle arrestors") would be attached to the pipeline at designed spacing to prevent the pipeline from collapsing under hydrostatic water pressure.

Except for the crossing of the Navy RELI cable at a depth of 185 feet (56 m), there would be no pipeline appurtenances in water depths of less than 600 feet (183 m); all buckle arrestors, the remaining two cable crossings, and the PLEMs and associated piping would all be at depths greater than 600 feet (183 m). In shallower depths, i.e., less than 600 feet (183 m), the occasional anode bracelets would constitute no more than a variation in the diameter of the pipelines and would provide no snagging or obstruction beyond the pipelines themselves. Pipeline technical characteristics are presented in Table 2.3-1 below.

Table 2.3-1 Offshore Pipeline Characteristics

Parameter	Characteristic
Pipeline Length (each)	22.77 miles (36.64 km)
Outside Diameter	24 inches (0.6 m)
Wall Thickness	0.875 inches (2.2 centimeters [cm])
Steel pipe material grade	API 5L X60[a]
Steel pipe material density	490 lb/ft^3 (7,850 kg/m^3)

Notes: kg/m^3 = kilograms per cubic meter; lb/ft^3 = pounds per cubic foot.
[a]American Petroleum Institute. January 2000. Recommended Practice 5L X60, Line Pipe, 42nd Ed.

The maximum operating pressure for each of the two 24-inch (0.6 m) diameter pipelines is 1,500 psig (1.05 million kg/m^2). Over the length of these pipelines, the pressure would decrease to 1,100 psig (773,400 kg/m^2) at the Ormond Beach Metering Station.

Normal operation of the twin subsea pipelines would be dictated by commercial flow requirements. Natural gas would flow at rates varying in accordance with delivery requirements. The metering station and instrumentation on the FSRU and within the Reliant Energy facility at Ormond Beach would serve as part of the safety and leak-detection system.

The offshore pipelines would comply with an operations plan that would be approved by both the USCG and CSLC.

The integrity of the subsea transmission pipelines would be monitored through visual inspection and maintenance pigging (described below). Title 49 CFR Parts 190 to 199 govern the construction, operation, and maintenance of the onshore and offshore parts of the transmission pipelines. The Applicant has prepared a preliminary 10-year plan that sets forth the surveys that would be conducted as part of the maintenance program. Annual remotely operated vessel surveys of the risers, anchors, and PLEM are included in the overall survey program.

Leaks could be detected using a pressure and mass balance system with equipment installed at both ends of the pipelines. This system would provide both alarm and automatic shutdown signals directly to the FSRU. The FSRU crew, supply boat captains, and helicopter pilots at sea would conduct leak detection routinely. Signs of gas leaks are bubbles breaking at the surface, which can be seen in most weather conditions. Also, because the pipeline's natural gas would be odorized at the FSRU, any leaks would likely be detectable by smell. Monthly routine patrols would specifically watch the sea surface. Supply boats would also carry gas detectors. Additional details on monitoring and metering may be found in Section 4.2, "Public Safety: Hazards and Risk Analysis."

Periodic internal inspection of the pipeline would be conducted using an intelligent pig.[8] Regular pipeline maintenance would include maintenance and intelligent pigging at intervals specified by the USDOT PHMSA, the Applicant's standard operating procedures, and CSLC regulations for offshore pipelines as specified in Article 3.3 (Oil and Gas Production Regulations) Section 2132(h) (Pipeline Operations and Maintenance) or when conditions warranted. The pigging would cover the entire pipeline and include the sections under Ormond Beach; however, no pigging activities would occur on the beach itself.

If pigging and surveillance operations determined that there was excessive corrosion or damage to the pipelines, additional analysis would be required to determine corrective

[8] Pigs are devices that are used to clean, inspect, and maintain pipelines, and to measure the wall thickness of the pipe and detect corrosion and other pipeline anomalies.

actions, up to and including replacement of pipeline segments. To conduct the pigging operations, gas would have to be vented to provide the differential pressure to drive the pig through the pipeline. The flexible risers would be inspected annually in accordance with the manufacturer's recommendations, which typically include pressure/hydrostatic tests and visual inspection.

2.3.2 Shore Crossing

The subsea pipelines would come ashore and extend beneath the beach and terminate at the proposed metering station on the existing Reliant Energy Ormond Beach Generating Station to tie into the SoCalGas system. HDB technology would be employed to place the pipelines at least 50 feet (15.2 m) below the surface of the beach and the adjacent sea level except at both ends of the crossing where the pipelines slope up to meet the entry and exit points. The maximum depth below ground surface would depend on the depth to sandstone, which is estimated between 50 and 75 feet (15.2 to 23 m), pending final geotechnical studies and final design (see Section 2.6.1, "Shore Crossing via HDB"). Each of the two HDB shore approaches for the Project is expected to be approximately 4,265 feet (1,300 m) in length and would be parallel to each other, with approximately 100 feet (30.5 m) of separation. The HDB staging area would be located on disturbed (previously occupied) land. The presence of wetlands near the shore crossing is discussed in Section 4.8, "Biological Resources – Terrestrial."

Operation of the pipelines within the shore crossing area would include periodic aboveground patrol of the ROW by the Applicant during leak detection surveys, valve operations, and visual inspections. Patrolling would also ensure that no activities, such as construction work that could potentially impact the integrity of the pipeline, were occurring.

A main line valve at the SoCalGas facility would separate the offshore facilities from the SoCalGas facilities and would serve as an emergency shutdown valve that would automatically close to isolate flow between the offshore transmission pipelines and the SoCalGas system in an emergency.

2.4 ONSHORE PIPELINES AND FACILITIES

Two new onshore pipelines, the Center Road Pipeline in Oxnard and the Line 225 Loop Pipeline in Santa Clarita, would be constructed. These pipelines, along with associated facilities such as a metering station for the Center Road Pipeline, a backup odorant injection system, and block valves on both pipelines, would be installed where existing pipelines are not large enough to accommodate the proposed additional supply. According to SoCalGas, the two onshore pipelines and expansion of the valve stations are the only major upgrades needed to accommodate an average daily increase of 800 MMcfd (22.7 million m^3 per day) (Bisi 2004).

Line 324 interconnects the Center Road Station with the Saugus Station in the Santa Clarita area. The gas flows from Saugus Station to Center Road Station and then to either the Los Angeles area to the south or the Santa Barbara area to the north. This existing system has sufficient spare capacity to receive the proposed additional average daily 800 MMcfd (22.7 million m^3) of natural gas and, therefore, would not need to be upgraded.

The precise location of the onshore pipeline alignments, e.g., which side of the street, would not be known until detailed engineering and substructure research would be performed and mapped onto the alignment drawings. However, the proposed alignments are known in sufficient detail to allow for environmental review and analysis. The final alignment of the pipeline within the proposed ROWs would be determined by detailed engineering design and analysis; until that alignment is known, the precise land ownership and location within public or private ROWs would not be known. Permanent easements and temporary construction easements would be required outside of private and public road ROWs. Permanent easements would range between 25 and 50 feet (7.6 and 15.2 m), depending on site-specific conditions. Nevertheless, SoCalGas would attempt to use existing farm roads and, where necessary, acquire easements immediately adjacent to farm roads to minimize disturbance to active agricultural fields. The pipelines would be installed on either side of the roadways identified in Figures 2.4-1 and 2.4-2. Additional information regarding the installation of pipelines in agricultural areas may be found in Section 4.5, "Agriculture and Soils."

In compliance with California Government Code § 7267 et seq., SoCalGas would make every reasonable effort to acquire easements expeditiously by negotiation, prior to exercising eminent domain. The easement rights would be appraised before the initiation of negotiations, and the property owner, or his or her designated representative, would be given an opportunity to accompany the appraiser during the inspection of the property. SoCalGas would establish an amount that it believes to be just compensation for the easements rights based on the appraisal and would provide the property owner with a written statement and summary of the basis for the compensation amount, which would not be less than the appraised value.

2.4.1 Center Road Pipeline and Facilities

2.4.1.1 Center Road Pipeline

The Project would include installation of approximately 14.7 miles (23.7 km) of new 36-inch (0.9 m) diameter pipeline with a maximum allowable operating pressure (MAOP) of 1,100 psi (773,400 kg/m^2) to transport natural gas from the Reliant Energy Ormond Beach Generating Station to the Center Road Valve Station. The new pipeline alignment would follow existing utility ROWs, public roads, and/or newly acquired easements. The proposed route is as follows:

- Begin at the new metering station within the Reliant Energy Ormond Beach Generating Station;
- Run north along the Southern California Edison electric transmission line ROW;
- Turn east on Hueneme Road, north on Nauman Road, west on Etting Road, and north on Hailes Road to Pleasant Valley Road;

- At Pleasant Valley Road, head southwest for approximately 1,000 feet (305 m) and then turn north through agricultural fields; Continue through agricultural fields, cross State Route (SR) 34 (East 5th Street), continue north along Del Norte Boulevard, and cross Sturgis Road to U.S. 101 (Ventura Freeway);
- Turn east along the U.S. 101 frontage road, then turn north and cross U.S. 101;
- Proceed northeast to Central Avenue, then southeast along Central Avenue and northeast along Beardsley Road;
- Head northeast for approximately 0.25 mile (0.4 km), then northwest along a flood control channel (the Santa Clara Diversion) to Santa Clara Avenue;
- Follow adjacent to Santa Clara Avenue northeast to SR 118 (Los Angeles Avenue);
- Head northwest along SR 118 for approximately 0.4 mile (0.6 km) to just before Clubhouse Drive, then head northeast for approximately 1.1 miles (1.8 km) and east for approximately 0.55 mile (0.9 km) along an unpaved road and Center Road (this segment of the proposed pipeline route differs from that described in the October 2004 Draft EIS/EIR); and
- Terminate at the Center Road Valve Station.

During the public comment period on the October 2004 Draft EIS/EIR, issues were raised concerning existing schools and potential future school sites. As a result, the Applicant has contacted and held discussions with three school districts—Mesa Union, Oxnard Union High, and Ocean View—as well as with SoCalGas, the CPUC, and the California Department of Education. The Mesa Union School District is not contemplating the construction of any new schools at this time; however, it did express concern about the placement of the pipeline near the Mesa Union School near the intersection of SR 118 (Los Angeles Avenue) and La Vista Avenue. As a result, the Applicant, in conjunction with SoCalGas, has proposed a new route for the pipeline near its northern terminus (from SR 118 to the Center Road Valve Station) to avoid the school completely. In the Oxnard Union High and Ocean View School Districts, the proposed pipeline would not be located adjacent to any existing schools (see Section 4.13, “Land Use,” for information regarding the alignment of the pipelines and concerns raised by the school districts and the California Department of Education about the feasibility of siting future schools along the pipeline ROW).

2.4.1.2 Ormond Beach Metering Station

Gas from the FSRU would be accepted into the SoCalGas transmission system at the Ormond Beach Metering Station, which would be located within the existing Reliant Energy Ormond Beach Generating Station. SoCalGas would install gas monitoring equipment to ensure gas quality and measure volume and pressure and would provide additional odorization monitoring and injection control. The Ormond Beach Metering Station would consist of 3.5-foot (1.1 m) tall aboveground valve actuators; 8-foot (2.4 m) blowdown stacks; a small instrument building (8 to 9 feet [2.4 to 2.7 m] tall); pig

Insert (1 of 2)

Figure 2.4.1 Center Road Pipeline: Proposed Route

Insert (2 of 2)

Figure 2.4-1 Center Road Pipeline: Proposed Route

Insert (1 of 2)

Figure 2.4-2 Proposed Line 225 Pipeline Loop Location

Insert (2 of 2)

Figure 2.4-2 Proposed Line 225 Pipeline Loop Location launchers and receivers (see Section 2.3.1, "Offshore Pipelines and Associated Facilities"); a gas odorant injection station; and concrete pads and foundation.

2.4.1.3 Backup Odorant Injection System

SoCalGas would maintain an odorant injection system at the Reliant Energy Ormond Beach Generating Station as a backup (as discussed previously, BHPB would inject odorant at the FSRU) to ensure sufficient concentration of odorant in the onshore pipelines. This injection system would consist of a 60-gallon (0.2 m^3) aboveground, non-pressurized storage vessel containing SpotLeak 1039, a concrete containment pad, and a pump. The odorant would be pressurized only at the terminus of the injection pump where a small amount of the odorant would be injected directly into the pipeline.

The tank and associated equipment would be enclosed within secondary containment, designed to contain 110 percent of the volume of the tank (approximately 66 gallons or 0.25 m^3), and a wall barrier.

2.4.1.4 Center Road Valve Station Expansion

Expansion of this facility would include pressure reduction/regulation valves and remote operations equipment. In addition, blowdown and pig-receiving equipment, concrete pads and foundations, and electrical and communications equipment and two small instrument buildings would be installed. (As required by 49 CFR Part 192.179c, pipelines would blow down, i.e., release the contents of the pipe or segment of pipe, as rapidly as possible.) The facilities would not be lit at night. The Center Road Valve Station, at the southwest corner of Center Road and La Vista Avenue, would be expanded by 16,000 square feet (1,490 m^2) to 40,000 square feet (3,720 m^2) for operation.

2.4.1.5 Main Line Block Valves

SoCalGas would install three new main line block valves along the Center Road Pipeline route and one new main line block valve in the Line 225 Loop. The length of pipeline between main line block valves would be approximately 3.8 miles (6.1 km) for the Center Road Pipeline and 3.5 miles (5.6 km) for the Line 225 Loop, both of which are less than the 8-mile (12.9 km) length that requires a Class 3 designation under 49 CFR Part 192.179. Both onshore pipelines would be designed and constructed to meet Class 3 requirements, which would provide a higher level of safety. Pipeline area classifications are defined in Table 4.2-14, "Pipeline Location Class Definitions." SoCalGas would install two 12-inch (0.3 m) valve assemblies at each main line block valve. The proposed blowdown assemblies (devices for providing controlled venting, or emptying, of the contents of a pressurized pipeline to perform inspections, maintenance, or repairs) would allow the Center Road Pipeline and Line 225 Loop to blow down in 15 and 9 minutes or less, respectively. A discussion of how block valves and blowdown times are relevant in terms of public safety is provided under Impact PS-4, "Potential Release of Odorized Natural Gas due to Accidental Damage to Onshore Pipelines," in Section 4.2.9.4, "Impact Analysis and Mitigation."

The main line block valves would likely be located out of the roadway in agricultural fields. They would be permanently installed within a fenced area with 3-foot (1 m) tall above-grade valve actuators, an 8-foot (2.4 m) blow-down stack, a small 8- to 9-foot (2.4 to 2.7 m) tall instrument building, and a concrete pad. The valve bodies would be buried. If the installations were located in the paved road, they would be in two buried concrete vaults, one for the main block valves and the other for the blow-down assemblies. The facilities would not be lit at night.

2.4.2 Line 225 Pipeline Loop and Facilities

2.4.2.1 Line 225 Pipeline Loop

The existing Line 225 transports gas supply north to the San Joaquin Valley and south to the Los Angeles basin. Installation of the proposed Line 225 Pipeline Loop in Santa Clarita is necessary to ensure that supplies flowing south to the Los Angeles basin are not constrained by supplies delivered from Line 324 at the Saugus Station. The proposed new loop pipeline would generally parallel the existing Line 225 Pipeline either in or near the existing ROWs within unpaved parts of the route. The proposed Line 225 Pipeline Loop would be 30 inches (0.76 m) in diameter, designed for an MAOP of 845 psi (594,100 kg/m^2), and extend approximately 7.7 miles (12.4 km) between Quigley Valve Station and the Honor Rancho Storage Facility. Along city and county roadways, the pipeline would parallel the existing Line 225 Pipeline to the extent practical. The proposed pipeline route is as follows:

- Begin at the Quigley Valve Station;
- Parallel the existing Line 225 Pipeline in a westerly direction to Via Princessa;
- Proceed west on Via Princessa to Oak Ridge, then north within Oak Ridge, then north within SR 126 (San Fernando Road and Magic Mountain Parkway), generally paralleling the existing Line 225 pipeline;
- Proceed northwest and parallel the Line 225 pipeline within SR 126, cross the South Fork Santa Clara River within the SR 126 bridge, and continue to McBean Parkway;
- Proceed northeast along McBean Parkway and deviate from the Line 225 pipeline alignment, cross the Santa Clara Rives with the McBean Parkway to Avenue Scott, cross San Francisquito Creek within Avenue Scott bridge, then northwest to Avenue Stanford;
- Proceed west along Avenue Stanford and rejoin the Line 225 pipeline alignment at the existing utility ROW; and
- Proceed northwest for approximately 1 mile (1.6 km) to the Honor Rancho Valve Station and Storage Facility through an existing utility ROW containing four pipelines, including existing Line 225 pipeline and seven overhead power lines.

The South Fork Santa Clara River crossing is a closed girder bridge; the remaining two crossings are open girder bridges. It is anticipated that the road bridges would not require significant improvements to accommodate the pipeline. The pipeline would hang underneath the open girder bridges, and the pipeline would be installed inside an open cell in the closed girder bridge. See Section 2.7.2, "Crossing Techniques," for more information on river crossing construction.

2.4.2.2 Quigley Valve Station Expansion

The proposed expansion would include pressure reduction valving and regulation facilities and pressure monitoring and remote operations controls for the proposed new Line 225 Pipeline Loop. In addition, blowdown and pig-receiving facilities, concrete pads and foundations, and electrical and communications equipment and two small instrument buildings would be installed. The facilities would not be lit at night.

2.4.2.3 Honor Rancho Valve Station

Modification of the valve station would be required for the proposed new Line 225 Pipeline Loop, including new control valves. This equipment would be placed within the existing facility footprint to the extent practical. If expansion is necessary, the station would expand approximately 50 feet by 75 feet (15.2 m by 23 m) or 3,750 square feet (348 m^2). The facilities would not be lit at night.

2.4.3 Maintenance of Onshore Pipelines and Facilities

Maintenance would include the following for the onshore segments of the pipelines and associated aboveground facilities:

- Visual inspection of the ROW and leak surveys;
- Inspection and maintenance of the corrosion-protection system;
- Pipeline identification and location for nearby third-party activities; and
- ROW and access maintenance, and pipeline marker maintenance.

The time intervals for the above maintenance activities would vary but would be in accordance with USDOT and CPUC regulations. SoCalGas has prepared a preliminary 10-year survey schedule that involves testing and inspection of every part of the pipeline system in compliance with the integrity management rule. (See Section 4.2.9.2, "Regulations Regarding Pipelines," for the discussion of 49 CFR Part 192 Subpart O for an explanation of this rule.) Inspection activities for SoCalGas's portion of the onshore facilities include in-line inspection (pigging) surveys and direct assessment.

To prevent damage to pipelines and infrastructure by outside third parties, the California One Call Law, Government Code § 4216, requires that excavators notify the Underground Service Alert at least two working days prior to initiating digging operations. The Underground Service Alert would then issue a report with a unique number, and SoCalGas would provide information about or mark/stake the horizontal path of its utilities and provide continuous surveillance during construction activities along its gas transmission pipeline system. Underground facilities would be exposed by hand digging prior to the use of power equipment such as backhoes.

SoCalGas would constantly monitor the gas transmission system from its existing gas operations control room using its supervisory control and data acquisition (SCADA) system. The information would be constantly transmitted to the gas control facility and monitored at all times. Automatic alarms would be triggered if gas delivery parameters were not met or if unusual conditions, such as a leak, were to occur in the system. SoCalGas control personnel would have the ability to remotely operate the control valves to mitigate any problem.

2.5 CONSTRUCTION AND INSTALLATION: FSRU AND VICINITY

The previous sections described the proposed Project facilities. Sections 2.5 to 2.7 discuss how the facilities would be constructed and installed. Equipment and vessels that would be used during FSRU installation, as well during offshore HDB and pipelaying operations, are summarized in Table 2.5-1.

Table 2.5-1 Pipeline Construction Vessels and Equipment, Use, and Duration of Use

Vessel/Equipment	Use	Duration
FSRU Mooring Construction		
2 tug supply vessels (15,000 hp)	Logistical support	20 days; 24 hrs/day standby each
1 crew boat (1,500 hp)	Transport of work crews	20 days; 2 hrs/day cruising, 14 hrs/day standby
1 construction barge (8,000 hp)	Installation of mooring system, PLET, and PLEM	20 days; 12 hrs/day operating; 12 hrs/day standby
1 tug (6,500 hp)	Barge positioning	20 days; 2 hrs/day assisting, 22 hrs/day standby
1 oceangoing tug (25,000 hp)	Logistical support	1 day; 2 hrs/day assisting, 22 hrs/day standby
Shore Crossing Construction		
1 HDB pipelay barge	Fabrication and installation of HDB pipeline sections	60 days
1 exit hole barge (4,000-6,000 hp)	Construction of transition trench	35 days
2 anchor handling towing/supply vessels (15,000 hp)	Pipelay barge positioning; navigation during mooring.	35 days
4 materials barges	Transport pipe and supplies	60 days
Offshore Pipelay Construction		
1 dynamically positioned pipelaying vessel (25,000 hp)	Pipelaying	35 days; 12 hrs/day operating, 12 hrs/day standby
2 tug supply vessels (15,000 hp)	Logistical support	35 days; 24 hrs/day standby each
1 crew boat (1,500 hp)	Transport of work crews	35 days; 2 hrs/day cruising, 14 hrs/day standby
1 tug and pipe barge (4,000 hp)	Pipe handling	10 days; 4 hrs/day cruising, 12 hrs/day standby
1 dock crane (35 tons; 130 hp)	Pipe handling and loading	8 hrs total

2.5.1 Floating Storage and Regasification Unit

Potential fabrication yards for the FSRU are in Japan, Korea, Spain, and Finland. All fabrication activities would adhere to the fabricator's own International Organization for Standardization (ISO) 9000 type of quality assurance program.[9] The USCG would require a quality management plan, the implementation of which would be independently checked by a verification agent such as a classification society on behalf of the USCG, in consultation with the CSLC, as would all offshore installation activities, including mooring pre-tensioning and hydrotesting. The FSRU would be towed from its fabrication point to the mooring location by two oceangoing tugs in accordance with a towing plan. This plan would be developed by the Applicant and submitted to the USCG and CSLC for approval before installation of the FSRU would occur (as discussed in Section 4.3, “Marine Traffic”). Two barges would transport anchors and equipment to the mooring location, and two supply vessels (at 4,500 horsepower [hp] each) would transport materials and crew.

As stated previously, before arrival from the overseas fabrication port, the FSRU would follow established ballast water exchange protocol in accordance with MARPOL and State of California and USCG requirements, including notification and exchange of ballast water outside the 200 NM (230 miles or 371 km) Exclusive Economic Zone limit.

2.5.2 Mooring System

Before mooring installation, additional site-specific surveys and testing would be performed to supplement the geophysical and geotechnical testing program already conducted by the Applicant and verified for use in this analysis, as discussed in Section 4.11, “Geologic Resources and Hazards.” The results of the additional testing, which would include a determination of the allowable anchor pull, would be used to coordinate layout positions of the anchor leg components. The geophysical and geotechnical work would be performed under the supervision of a California Registered Geologist or a California Registered Civil Engineer approved by the USCG and/or MMS and in consultation with the CSLC.

Installation of the mooring point and tie-in of the FSRU is anticipated to require approximately 24 days (20 days for mooring point installation and 4 days for tie-in), using 12-hour workdays. During nine of these 24 days, nine conventional drag-embedded anchors would be placed on the seabed and embedded with the mooring lines attached. Anchors would be positioned within their design limits and mooring or anchoring of the installation vessels would not be required. During the 24-day tie-in period, the FSRU would arrive at the site with the mooring turret and anchor-pulling equipment pre-installed. Two tugs would hold the FSRU in place, and a third tug would be used to retrieve and hook up the nine mooring legs to the FSRU turret. Hook-up vessels would retrieve the end of each anchor leg and pass it over to the FSRU turret, which would pull in each anchor line and make the final connection between the FSRU

[9] ISO 9000 is an international management quality control system used in business-to-business dealings.

and the anchor leg. After all legs were connected, final adjustments would be made until the correct tension was present in each anchor leg. All risers and connecting cables would then be similarly retrieved from the seabed and passed over to the FSRU for final connection to the FSRU turret.

Following FSRU connection, a full hydrostatic test would then be conducted to check the pressure integrity of product swivels, piping, and valves. All testing and checking would be subject to classification society, independent, third-party verification.

All equipment provided on the turret, including lubrication systems, leak detection systems, and electrical and hydraulic systems, would be function-tested by the Applicant and its contractors with the independent third-party verification of a classification society.

2.6 CONSTRUCTION AND INSTALLATION: OFFSHORE PIPELINES AND SHORE CROSSING

The two subsea pipelines between the FSRU and shore would be laid between individual offshore target boxes, beginning at the HDB exit point, located approximately 3,921 feet (1,195 m) offshore, and running to a location near the PLEM at a depth of 2,850 feet (869 m). The target boxes are radio transmitters placed at predetermined locations using a global positioning system (GPS). Each pipeline would tie in to an HDB pipeline, which would run to the Ormond Beach Metering Station shore crossing. As shown on Figure 2.6-1, the HDBs would be drilled beginning inland from the beach, with an offshore barge supporting the construction operations. The pipe for the HDBs would be pulled into the casing from either direction.

The installation of the two 24-inch (0.6 m) shore crossing pipelines would be accomplished by first drilling 36-inch (0.9 m) diameter boreholes from shore toward the offshore exit point. A 36-inch (0.9 m) diameter casing would be advanced through each borehole as it is drilled. The 24-inch (0.6 m) diameter natural gas pipelines would then be pulled through the 36-inch (0.9 m) diameter casings, either from offshore to onshore or vice versa. HDB operations are described in more detail in the following section.

2.6.1 Shore Crossing via HDB

Two HDB borings, one for each pipeline, would be drilled for 0.8 mile (1.3 km) to cross the shore at the landfall site. The minimum depth below ground surface for the HDB borings as they cross beneath the shore is 50 feet (15.2 m) except at both ends of the crossing where the pipelines would slope up to the entry and exit points, while the maximum depth would depend on the depth to sandstone, which is estimated between 50 and 75 feet (15.2 to 23 m). HDB has been used since 1977 to install large-diameter pipelines beneath environmentally sensitive areas such as waterways and surf zones. According to preliminary geotechnical studies, the geologic formation through which the proposed Cabrillo Port landfall would be installed is primarily sand, which is suitable for employing HDB (Cherrington 2006, see Appendix D4).

Insert (1 of 2)

Figure 2.6-1 Horizontal Directional Boring Schematic

Insert (2 of 2)

Figure 2.6-1 Horizontal Directional Boring

Features of the HDB method include a thrusting unit located at the surface entry point, a rotating drill head, an internal pumping unit for drilling fluid and entrained cuttings, and an articulated head for directional control. The main difference between HDB and HDD is that in the HDB methodology a pump, located near the drill head, is used to return excess drilling fluid and cutting spoils back to the drill rig for separation and recycling. As a result, drilling can occur using lower drilling fluid pressure, which minimizes or eliminates the risk of these fluids escaping into the surrounding formation or to the surface.

However, in the unlikely event that drilling fluid is lost to the surrounding formation or the surface, a contingency plan that address remedial actions, approved by regulatory agencies, would be implemented (see Appendix D1). The HDB system employs pressure sensors near the cutting head to monitor the borehole fluid pressure at all times and is controlled from the surface.

The cutting head creates a hole having a diameter approximately 25 percent greater than the outside diameter of the pipe or casing to be installed. The depth and direction of the drill head is controlled at the surface using the Directional Control System, which uses conventional sensor technology connected to the surface by wire. The bore path would be tracked using a surface electromagnetic tracking system (Cherrington 2006).

During the HDB process, drilling fluid is used. This drilling fluid is composed of 95 to 98 percent fresh water and 2 to 5 percent bentonite, a naturally occurring clay mixed with a small amount of extending polymer (polyacrylamide). This fluid serves the flowing functions:

- Transportation of drilling spoils back to the surface at the entry point;
- Cooling and cleaning of the cutters on the drill head;
- Reduction in friction between the drill pipe and the walls of the hole;
- Stabilization of the drilled hole;
- Transmission of hydraulic power to turn the drill head;
- Hydraulic excavation of the soil; and
- Modification of the soil to reduce its shear strength.

Several surveying options may be used during the HDB process. Multiple coils or an antenna may be set on the beach, sea floor, or deck of a barge. If the use of a coil or antenna would impact sensitive native habitats, gyroscopic directional sensors would be employed within the HDB drilling system, and surface directional control methods would not be used. Section 4, “The HDB Process” in Appendix D4 discusses these options in more detail (Cherrington 2006).

At the conclusion of HDB drilling, any excess drilling fluid and spoils that are collected through the HDB return system would be disposed of in accordance with Federal, State, and local regulations. During initial project evaluation, the Applicant or its contractor would test to determine whether any contaminants exist along the HDB drilling path. Subsurface samples would be collected every 500 to 1,000 feet (152 to 305 m) along the path and analyzed for heavy metals, total petroleum hydrocarbons, volatile organic compounds, and semi-volatile organic compounds. If elevated levels of any of these contaminants were detected in the samples, the excess drilling fluid and spoils would be disposed of at a licensed hazardous waste facility. If no contamination were detected, the material would be disposed of at a conventional approved disposal site (Cherrington 2006).

At each of the onshore entry points, located on Reliant Energy property, an area approximately 250 feet by 325 feet (76 m by 99 m), or 1.9 acres (0.8 ha), would be required for equipment, supplies, parking, etc. A typical HDB equipment layout for an entry point is presented in Figure 2.6-2. At the entry point for each of the two pipelines, a sloped HDB launching pit, measuring approximately 22 feet by 103 feet (6.7 m by 31.4 m) and 20 feet (6.1 m) below ground surface at the deepest end, would be excavated to align the drill rig with the entry angle of the borehole (Cherrington 2006).

A near-shore support barge and associated support vessels would be required at each HDB exit point. A typical offshore HDB equipment layout is presented in Figure 2.6-3. This equipment would be used to create a “transition excavation.” The transition excavation is a 150-foot (46 m) wide by 200-foot (61 m) long by 5-foot (1.5 m) deep pit located at the offshore pipeline exit point that is used to extract and contain any drilling fluids released, to remove the HDB bottom hole assembly (drill head) and internal drilling fluid supply and return pipes upon exit, and to prepare the end of the 36-inch (0.9 m) diameter casing for the 24-inch (0.6 m) diameter pipeline. Each of the two 24-inch (0.6 m) diameter pipelines would be placed inside a 36-inch (0.9 m) diameter casing.

The Applicant has prepared an anchor mitigation plan for temporary anchors and moorings to be used by nearshore vessels operating in support of the HDB process (MPMI 2005a). This document provides information on the type of anchors to be used, procedures for their installation and recovery, and mitigation measures to minimize effects on the seafloor. The plan was prepared based on established local marine practices that are routinely employed for West Coast subsea projects. All anchor deployment and recovery operations would be performed during daylight hours using differential GPS navigation to ensure location accuracy. Figure 2.6-4 presents the proposed mooring arrangement for the Project work barges and support vessels; this arrangement may be amended once the contractor and marine equipment spreads have been selected. A final Anchor Mitigation Plan would be submitted at that time. Each of the vessels listed below would require mooring.

- Work Barges – Work barges provide a stable platform from which pipelaying operations can be conducted and include the nearshore pipelay/HDB support equipment spread barge and the exit hole barge. The nearshore pipelay/HDB barge would be approximately 400 feet (122 m) long with up to an 8-point mooring system, including 10-ton (9,100 kg) anchors. The exit hole barge would

Insert (1 of 2)

Figure 2.6-2 Typical Onshore Horizontal Directional Boring Equipment Layout

Insert (2 of 2)

Figure 2.6-2 Typical Onshore Horizontal Directional Boring Equipment Layout

Insert (1 of 2)

Figure 2.6-3 Typical Offshore Horizontal Directional Boring Equipment Layout

Insert (2 of 2)

Figure 2.6-3 Typical Offshore Horizontal Directional Boring Equipment Layout

Insert (1 of 2)

Figure 2.6-4 Proposed Offshore Horizontal Directional Boring Vessel Mooring Arrangement

Insert (2 of 2)

Figure 2.6-4 Proposed Offshore Horizontal Directional Boring Vessel Mooring Arrangement range from 220 to 400 feet (67 to 122 m) long with up to a 9-point mooring system, including 10-ton (9,100 kg) anchors.

- Anchor Handling Towing/Supply (AHTS) Vessel – Specifically constructed to install and retrieve all temporary moorings, AHTS vessels are equipped with 150- to 200-ton (136,000 to 181,400 kg) capacity winches. Typical AHTS vessels are 190 to 225 feet (58 to 69 m) long, with up to 15,000 hp engines.
- Anchor Handling Vessel (AHV) – An AHV would operate the barge's onboard anchors to support the survey and sampling equipment and personnel. Typical West Coast AHVs for barge support are 100 to 185 feet (30.5 to 56 m) long with 4,000 to 6,000 hp engines.

In addition, temporary dead man anchors, i.e., heavy solid objects typically buried below the ground surface, would be used to hold one end of each of the subsea pipelines in place while the piping was welded and subsequently installed on the seafloor.

The HDB boreholes would exit the seafloor at a depth of approximately 42 feet (12.8 m) below sea level, located approximately 3,921 feet (1,195 m) offshore. The nearshore/draft limited HDB and pipelaying phases of the Project would typically use three equipment spreads: a nearshore/HDB pipelay spread, an HDB exit hole barge spread, and a deepwater pipelay spread. Permits and approvals from multiple jurisdictional agencies (including the CSLC, California Coastal Commission, U.S. Army Corps of Engineers, Los Angeles Regional Water Quality Control Board [LARWQCB], California Department of Fish and Game [CDFG], NOAA, California Air Resources Board, and Ventura County Air Pollution Control District) would be secured prior to mobilization, and the proposed vessel and mooring locations would be published in the USCG's *Notice to Mariners* and the Joint Oil Fisheries Liaison Office's *Notice to Fishers*.

The vessels would be equipped with safety and spill response equipment and trained personnel in accordance with an approved emergency action and incident response plan (BHPB 2004). The estimated area of seafloor impacted by nearshore HDB and pipelaying activities is provided in Table 2.6-1.

Table 2.6-1 Seafloor Area Impacted by HDB Operations

Description	Quantity	Length (ft. / m)	Width (ft. / m)	Total Impacted Seafloor Area ($ft.^2$ / m^2)
HDB pipelay barge moorings	32	20 / 6.1	60 / 18.3	38,400 / 3,570
HDB pipelay barge support vessel moorings	6	20 / 6.1	60 / 18.3	7,200 / 670
Exit hole drilling barge moorings	9	20 / 6.1	60 / 18.3	10,800 / 1,000
Exit hole barge support vessel moorings	2	20 / 6.1	60 / 18.3	2,400 / 223
HDB pipelaying/installation	2	5,050 / 1,540	6 / 1.8	60,600 / 5,630
HDB transition trench (estimated)[a]	1	200 / 61	150 / 46	30,000 / 2,790

Note:
[a]Final size to be determined by selected contractor.

Preliminary bathymetric surveys have not identified any hard bottom habitats or other resources that would be substantially impacted during mooring or HDB pipelay/pull-in operations. The Applicant believes that ocean currents would infill the HDB transition trench with sediment (see Appendix D3, “HDB Nearshore Pipeline Project Marine Operations”).

The Applicant has prepared a Drilling Fluid Release Monitoring Plan, which contains training, monitoring, and release response requirements (Brungardt Honomichl 2006). The selected HDB contractor would be required to incorporate the measures contained in this monitoring plan into its work plan.

Based on past experience, it is anticipated that within the last 100 feet (30.5 m) of the seaward extent of the bore, the drill would pass through the mobile or transport sand zone, which would likely cause the drill to stick; prior to exiting the boreholes onto the sea floor, therefore, the Applicant would evaluate the drilling conditions to determine if the drill would require drilling fluid, fresh water, and/or salt water for lubrication. At this time, the Applicant believes that it is unlikely that drilling would be able to proceed without the use of drilling fluid. As a result, the Applicant has conservatively estimated that up to approximately 10,000 gallons (38 m^3) of drilling fluid (5,000 gallons [19 m^3] per HDB installation) could be released to the seafloor as the bores exit into the transition excavation, but is likely to be significantly less (Cherrington 2006).

During the exit phase, the HDB drilling head suction pump, located near the cutting head, would be continuously operated and coordinated with divers and airlift suction equipment on the sea floor near the exit point to withdraw and control drilling fluid with lightweight flocs (masses resembling wool formed by the aggregation of a number of fine suspended particles) clouding the surrounding seawater. The vacuumed drilling fluid and seawater would be collected in holding tanks at the surface or in supporting barge for disposal. To minimize the impact the presence of any drilling fluid on the seafloor upon exiting, operations would be restricted to daylight hours and mild or calm seas (Cherrington 2006).

Whether water or drilling fluid is used, the internal HDB pump would be used to draw in any excess drilling fluid while exiting to minimize any release to the ocean. Upon breaking through to the sea floor, no drilling fluid will be pumped through the cutting head. The transition excavation, measuring an estimated 150 feet by 200 (46 m by 61 m) feet and excavated to 5 feet (1.5 m) below the seafloor, would also serve as a sump to contain any drilling fluid that could be released. Because of its higher specific gravity, the drilling fluid would collect on the bottom of the transition excavation, from which it would be pumped to a support barge for subsequent disposal on shore (Brungardt Honomichl 2006).

The HDB would be drilled from the landward entrance point at the Reliant Energy Ormond Beach Generating Station shore crossing to the offshore pipestringing site. After the onshore HDB rig drills the holes for the pipelines, the pipe would be pulled through the pre-drilled holes either from offshore to onshore or vice versa. The curvature of the HDB hole would be limited based on the allowable radius necessary to pull the pipeline through and would be determined through an analysis of installation and operating loads and stress.

The anticipated construction workforce for HDB is approximately 15 specialized craftsmen in total. Completion of HDB operations is projected to require 108 days, 24 hours per day/seven days per week using single and double 12-hour shifts, depending on the activity being performed (Cherrington 2006).

2.6.2 Offshore Pipelines

Pipeline installation would occur over 35 days. The offshore pipeline installation would employ up to 200 non-local workers, who would be housed on the pipelaying barge during construction activities. The offshore pipeline installation would consist of the following steps: (1) pre-lay survey; (2) offshore pipeline preparation, welding, and testing; (3) transport of materials to the site; (4) pipelaying; and (5) post-lay testing.

2.6.2.1 Pre-Lay Survey

Information provided by the Applicant concerning ocean bottom hazards has been review by the EIS/EIR team and has been determined to be sufficient for completing the environmental review for the Project. However, additional studies are needed for the final design. A pre-lay hazard survey would be completed well in advance of pipeline construction and compared with previous bottom hazard surveys. The pre-lay hazard survey would consist of the following studies:

- A wide area swath bathymetry program to evaluate turbidity flow pathways from canyons outside of the immediate project area;
- A near-bottom geophysical survey using side-scan sonar and subbottom profiler data of the pipeline routes and anchorage area;
- A high-resolution multi-channel seismic survey to evaluate conditions in the areas of two potentially active faults crossed by the proposed pipeline route (as may be determined by the MMS);
- Shallow geotechnical borings at each anchor location and PLEM location to assess anchoring conditions and PLEM foundation conditions;
- Shallow geotechnical borings at selected locations along the pipeline route to evaluate soil conditions;
- Shallow geotechnical borings within canyon sidewalls adjacent to the proposed pipeline route to assess soil conditions relative to slope stability; and
- Shallow geotechnical borings along the HDB path to evaluate soil conditions for HDB installation.

The offshore ROW would be prepared for construction before the arrival of the pipelaying equipment. Preparation activities would also occur at the cable crossings and the exit holes of the HDB.

2.6.2.2 Transport of Materials to the Site

The pipelaying vessel would mobilize with essential equipment. Supply vessels would mobilize all additional and necessary equipment, materials, and personnel. Before transport of the pipes to the pipelaying vessel, all pipe joints would be checked. The pipes would be loaded in a nearby port on no more than four cargo barges for transport to the pipelaying vessel. The selected port would be determined based on the supply source of the pipe. The exact number of trips would depend on the size of the barges, the port of origin, and the level of safe loading for the barges. Pipes that were transported to the lay vessel would already have a fusion-bonded epoxy and concrete coating, as required. During unloading of pipes from the cargo barge using a crane and sling, a visual inspection would be conducted to detect any damage to pipe during transit. Pipe joints failing to meet the requirements of the visual inspections would be marked for immediate repair or rejection.

2.6.2.3 Offshore Pipeline Preparation, Welding, and Testing

The twin pipelines are described above in Section 2.3.1, "Offshore Pipelines and Associated Facilities." During pipe fabrication on the pipelaying vessel, the ends of the pipe joints would be cleaned and aligned, and the welding passes would be made. The field joint would then pass through a non-destructive examination station where the contractor's and a third party's welding inspectors would examine the completed weld to verify its quality. If the weld were to contain an unacceptable defect, the defect would be removed, and the weld would be repaired and re-examined. All welds would be inspected.

After the non-destructive equipment examination, the field joint would be coated with an anti-corrosion coating compatible with that applied onshore. The coating of all field welds would be visually inspected and examined with an electronic device to detect coating defects. All coating defects would be repaired before the pipe enters the water. All welding and coating would be completed in accordance with 49 CFR Part 192 and the current edition of American Petroleum Institute (API) Standard 1104. Inspection acceptance would be in accordance with American Welding Society (AWS) requirements.

2.6.2.4 Pipeline Laying

Pipeline construction would require the use of one deepwater pipelay spread, which includes all of the vessels and crew required to lay both subsea pipelines. The dynamically positioned pipelaying vessel (DPV) would operate at an average 35 percent loading, using ten diesel-powered welding units and two tug supply vessels, which would provide logistical support on a 24-hour basis for 35 days. Using a DPV would eliminate the need to place anchors along the route during pipelaying operations. Construction equipment would also include one 35-ton (31,750 kg) capacity diesel-powered crane working 8-hour days, and four pipe barges, needed to transport pipe and material offshore. The pipe would be transported from shore to the DPV using the supply barges and would be offloaded using the crane on the DPV.

The DPV would start at the offshore entry points of the HDB. The established pipeline lay corridor would be programmed into the pipelaying vessel's navigation system. The DPV would align itself with the ends of the pipelines installed via HDB and the laydown heads would be pulled onboard. The next pipeline line joints would be lined up with the HDB pipe string and then the welding process would occur. Following welding, inspection, and coating, the DPV would move ahead the length of that one joint to repeat the process. A curved metal lattice tail called a "stinger" would extend beyond the edge of the vessel and be used to lay the pipe on the seabed without causing any kinks or buckles. A "sleeper," or bridge, would be placed over the cables on which the pipelines would be placed. A chase boat (a boat that follows a lay vessel) equipped with a remotely operated vehicle would be used to monitor the touchdown of pipe on the ocean floor. The pipelaying vessel would use a differential GPS that receives satellite communications to accurately position itself over the seafloor. The offshore pipelines would be installed 50 feet (15.2 m) to each side of the centerline of the route. The installation contractor would perform engineering calculations to ensure that pipeline stress during installation would not exceed industry-accepted limits. Pipeline stress during installation would be controlled through adjustment and control of the laying tension.

2.6.2.5 Post-Lay Testing

The offshore pipeline segments would be tested in accordance with USDOT regulations contained in 49 CFR Part 192. The number and locations of test sections would depend on pipeline class location, elevation differences along the route, and construction constraints. (See the discussion Pipeline Area Classes in Section 4.2.9.2, "Regulations Regarding Pipelines.")

Before hydrostatic testing, a sizing plate would be installed on a pig and pushed through the pipelines to verify that the pipelines did not sustain any damage during installation. Approximately 2.5 million gallons (9,500 m^3) of test water would be drawn from appropriate and approved sources, likely derived from the City of Oxnard municipal supply. The water would be sent from shore through one of the two 24-inch (0.6 m) diameter pipelines to the FSRU and returned to shore for disposal through the other 24-inch (0.6 m) diameter pipeline. The Applicant would treat the hydrostatic test water with an oxygen scavenger (TROS TC1000 at less than 100 parts per million [ppm]) and a corrosion inhibitor (CorrTreat 77-781 at less than 75 ppm). If a residence time in excess of 7 days is required, a biocide (Troskill 88 at less than 50 ppm) would also be added.

The hydrostatic test water would be collected after use and disposed of onshore in accordance with Federal, State and local regulations; therefore, it would not be discharged to the ocean (Hann 2005).

2.6.2.6 Other Right-of-Way Crossings

The proposed subsea pipelines would not cross any known Federal or State oil and gas leases, pipelines, or pipeline ROWs, but would, as previously described, cross three fiber optic cables.

All cable crossings are located outside of State waters. The cable owners have been notified of the proposed pipeline routing, and their approval of cable crossings has been requested. Existing cables would be protected at the crossings by installing sandbags, concrete mats, and/or "sleepers," which are fabricated steel pipe supports designed to hold the pipeline off the sea floor while protecting against sagging and abrasion of the pipe walls.

2.7 CONSTRUCTION AND INSTALLATION: ONSHORE PIPELINES AND FACILITIES

2.7.1 Onshore Pipeline Construction Sequence

Figure 2.7-1 shows a typical onshore pipeline construction sequence. Onshore pipeline construction is expected to begin in the first quarter of 2009 and to require approximately nine months to complete. Onshore pipeline construction would typically proceed at 300 to 500 feet (91 to 152 m) per day through city streets and up to 600 to 700 feet (183 to 213 m) per day through agricultural areas, including orchards (primarily at the northern end of the Center Road pipeline). The final four weeks of the construction period would be used for testing and final tie-in of the lines. Both the pipeline from shore to the Center Road Valve Station and the pipeline in Santa Clarita would be constructed concurrently. The water crossings would also be staged and conducted concurrent with the three pipeline spreads.

Onshore pipeline construction would occur six days per week (Monday through Saturday), from 7 a.m. to 7 p.m., although the City of Santa Clarita Planning Office has indicated that the westernmost portion of the proposed new Line 225 Loop may need to be constructed at night in industrial zones (Follstad 2004). Biological and cultural resource monitors and other compliance monitors would be on site during construction, as required by regulatory agencies. SoCalGas would implement its Water Quality Construction Best Management Practices Manual (Sempra 2002) to reduce or eliminate pollutants in runoff from their construction projects. Best management practices (BMPs) included in the SoCalGas manual include sediment control, waste management and materials control, non-stormwater discharge control, and erosion control and soil stabilization. A construction workforce of approximately 100 to 120 personnel for each pipeline would be employed on the Project during the peak construction period. Approximately 50 percent of these workers would come from the three counties surrounding the Project site.

SoCalGas would reduce disruption in residential areas during construction by implementing standard construction procedures, which include the following measures:

- Leave mature trees and landscaping within the edge of the construction work area unless removal is necessary for safe operations of construction equipment;
- Place metal plates over open trenches or install safety fencing at the edge of the construction work area adjacent to residences;

Insert (1 of 2)

Figure 2.7-1 Typical Onshore Pipeline Construction Sequence

Insert (2 of 2)

Figure 2.7-1 Typical Onshore Pipeline Construction Sequence

- Limit the construction ROW to the minimum width necessary to safely conduct the construction work; and
- Maintain a minimum of 25 feet (7.6 m) between the residence and the proposed construction work area, where reasonably possible.

Section 4.13, "Land Use," provides additional information on construction near residences, businesses, and schools. Section 4.17, "Transportation" provides information on impacts to vehicle traffic and public transit.

Roadway intersection crossings would typically take 30 days to complete and would be performed by special crossing crews. Intersection crossings would be performed in four phases: sawcutting and location/identification of substructures; excavation of the trench; installation of the pipeline, normally half an intersection at a time to allow traffic flow; and backfilling and paving. Between phases, the trench would be covered with steel plates and the roadway would remain open to traffic.

Large intersections and heavily traveled roadways may require boring rather than trenching. Bore pits would be constructed on each side of the intersection or roadway. Because of their size, these pits could not be covered with steel plates but would be protected using pre-cast concrete barriers or steel fencing during construction. Boring beneath roadways and intersections would require approximately 30 to 40 days to complete. Two types of bore may be used: slick bore and cased bore. A slick bore is an uncased horizontal conventional bore and no drilling fluids are used. A cased bore is the same as a slick bore except that the pipeline is enclosed within a larger diameter pipe, or casing; again, no drilling fluids would be used.

Most soil encountered during trench construction within roadways and undeveloped areas would be clean fill material or clean native soil. However, prior to construction and during the planning phase of the Project, the construction route would be screened to determine whether any known contaminated sites could be encountered. The screening would include a review of the Environmental Data Resources, Inc. (EDR) database of known contaminated sites (see Appendix K), consultation with Federal, State, and local agencies that maintain historical information on hazardous waste/material locations, and a visual inspection of soil borings collected during the engineering phase. If any contaminated sites were identified, every effort would be made to avoid them. If contaminated sites could not be avoided, a detailed contingency plan would be prepared, as provided for in Impact HAZ-2c in Section 4.12, "Hazardous Materials," and implemented during construction.

During construction, temporary construction easements and workspaces would be established as summarized in Tables 2.1-3 and 2.1-4 above and described in the sections below.

In agricultural areas, SoCalGas would obtain a temporary construction easement to secure adequate workspace. Typically, an approximately 80-foot (24.4 m) wide ROW would be required for a 30- to 36-inch (0.76 to 0.9 m) diameter pipeline. Along the northern end of the Center Road Pipeline, from the intersection of SR 118 (Los Angeles

Avenue) and Clubhouse Drive to the Center Road Valve Station, the ROW would be 100 feet (30.5 m) wide. Once the construction schedule is developed, SoCalGas would engage in pre-construction discussions with farmers and landowners to notify them in advance when construction would occur on their property to minimize impacts to their crops or to planting or harvesting operations.

Should additional temporary workspace be required during construction operations due to unforeseen circumstances, SoCalGas and the biological and cultural monitors would perform clearance surveys of the proposed additional workspace prior to expanding the footprint of the work area to ensure that no regulated resources, e.g., riparian habitat, listed species or listed species habitat or cultural resources, would be affected. If regulated resources are present and unavoidable, and the workspace is necessary, SoCalGas would consult with the CDFG, U.S. Fish and Wildlife Service, or other applicable resource agencies to obtain approval for the additional workspace prior to mobilization into that area.

Construction of the pipeline within the existing paved roads would require temporary closure of at least one lane in accordance with a traffic control plan, which would be submitted by SoCalGas and approved by the responsible jurisdiction (affected county or municipality). Appropriate warning signs would be placed at strategic locations to warn drivers of the closed lanes. Flagmen could be used at busy intersections or roadways. Construction of temporary access roads and work strips would be required along unpaved roads in agricultural areas. Conventional boring techniques may be employed to install the pipeline beneath highways and railroads. Additional information is provided in Section 4.17, "Transportation."

Onshore pipeline construction would be conducted using one or two main construction "spreads" (workers and equipment) for each onshore pipeline. As shown on Figure 2.7-1, construction would proceed in the following general order: (1) pre-construction activities, including surveying and staking and ROW clearing or pavement cutting; (2) trenching; (3) hauling, stringing, and bending the line pipe; (4) lowering in, line-up, and welding; (5) weld inspection; (6) application of protective coating to weld joints; (7) backfilling; (8) ROW cleanup, paving, and restoration; and (9) hydrostatic testing.

2.7.1.1 Pre-Construction Activities

Onshore pipeline construction work would begin with a ROW survey, property owner notifications, and a one-call notification to identify utilities, road crossings, and other uses that may be impacted by the construction. The construction ROW and extra workspaces necessary for boring beneath highways and railroads and the ROW required for trenching would be cleared to remove obstructions. Fences would be cut and braced as necessary.

2.7.1.2 Trenching

After clearing an area, an approximately 8-foot (2.4 m) wide by 7-foot (2.1 m) deep trench would be excavated with a backhoe or trencher. The depth could vary if special conditions were encountered, e.g., crossing existing substructures. Previously identified buried utilities such as other pipelines, cables, water mains, and sewers would be located by hand digging prior to trenching. Blasting would not be required. Trees would be removed, if necessary, using a bulldozer.

If groundwater were encountered during construction, an appropriate method for managing it would be selected. Options typically considered for groundwater management are to obtain a NPDES permit from the LARWQCB or initiate coverage under a RWQCB General NPDES Permit for discharge to a surface drainage; obtain authorization to send the water to a local publicly owned treatment works (POTW); or dispose of the water at a commercial treatment, storage, and disposal facility (TSDF). The selected option would be implemented depending on the best alternative for operational efficiency.

The dewatering technique would be determined by the option selected. Typically, groundwater is pumped to a discharge location, a holding tank, a tank truck, or another approved location. BMPs would be employed during pumping and discharge and, if necessary, treatment options would be used to comply with applicable regulatory requirements. If sampling and analysis are required, a sample would be collected and analyzed for constituents required by the RWQCB, POTW, or TSDF, depending on the option implemented prior to discharge to surface waters.

2.7.1.3 Hauling, Stringing, and Bending

After trenching, pipestringing trucks would transport the pipe in 40-foot to 80-foot (12.2 m to 24.4 m) lengths to the pipeline ROW. Where sufficient space exists, trucks would carry the pipe along the ROW; otherwise, existing roads would be used. Sideboom tractors would unload the pipe joints and lay them end to end beside the trench line for line-up and welding. SoCalGas personnel would conduct tests along the pipe, field joints, fittings, and bends to locate any coating discontinuities such as thinning or other mechanical damage that could allow moisture to reach the pipe. Repairs would be made as necessary before lowering the pipe into the trench.

The pipe would be bent in the field, vertically and horizontally, to fit the trench contour. Construction in roadways with existing substructures may require pipe fittings for which bending in the field would not be practical. In these cases, manufactured or shop-made bends would be used.

Fugitive dust emissions during earth-moving operations would be controlled using water trucks equipped with fine-spray nozzles. At least 30,000 gallons (114 m^3) of water would be used per day for dust suppression. The most likely source would be municipal water purchased from the City of Oxnard municipal water supply or other similar commercial source.

2.7.1.4 Lowering In, Line-up, and Welding

After laying the pipe next to the trench, the pipe would be lowered into the trench by sideboom tractors, which would be spaced so that the weight of unsupported pipe would not cause mechanical damage. Welds inside the trench would be required and would be made at the final elevation. Following the line-up crew, the welding crew would apply the remaining weld passes to complete the weld. Each weld would require pipe handling for line-up, coating, and backfilling, in addition to normal welding and weld inspection.

Welders certified and tested to meet SoCalGas procedures would perform all field welding. Welding would comply with the specifications of all applicable State and Federal regulations, including USDOT 49 CFR Part 192 (for natural gas pipelines) and CPUC regulations regarding gas pipelines, General Order 112E.

All welds would be inspected using appropriate non-destructive methods. Weld inspection records would be interpreted for acceptability according to applicable regulatory requirements. All rejected welds would be repaired or replaced as necessary and re-inspected. SoCalGas or its contractor(s) would retain the weld inspection reports and a record indicating the locations of welds.

2.7.1.5 Application of Protective Coating to Weld Joints

Epoxy pipeline coating would be applied at the pipe mill before delivery to the construction site. After the pipe has been welded and inspected, fusion-bonded or two-part epoxy would be applied to all field weld joints. A detection test would be conducted along the pipe to locate any coating discontinuities, such as thinning, or other mechanical damage that could allow moisture to reach the pipe. Where found defective, the coating would be repaired.

2.7.1.6 Backfilling

Soils removed during excavation would be segregated to separate topsoil from subsoil, where necessary, which would subsequently be used to backfill the trench following pipeline placement and inspection. Spoils would generally be returned to the trench within one week of trenching. The spoils would be screened using standard construction screening equipment, as required. The pipe would be covered along the sides and the top with a minimum of 6 to 12 inches (0.15 to 0.3 m) of native fill free of rocks, then covered with native backfill to grade.

In certain areas where the pipe coating might be damaged by abrasive soils along the bottom of the trench, clean sand or earthen backfill would be used to pad the pipeline. The backfill in the remainder of the trench above the padding would be native material excavated during trenching. The segregated topsoil would be used to cap the trench. Backfilled soil would be compacted using a sheepsfoot compactor, vibratory roller, or hydraulic tamper before paving. Compaction density and compaction testing would be performed in accordance with the affected local jurisdiction’s requirements.

2.7.1.7 Right-of-Way Cleanup, Paving, and Restoration

Necessary cleanup, paving, and restoration would entail repairing the trench cut within the roadway by paving; re-contouring the unpaved ROW; and removing debris, construction signs, surplus material, and equipment from construction areas. Erosion and drainage control measures such as water bars, drainage ditches, culverts, silt fences, and energy dissipaters would be installed where necessary to control erosion. Revegetation and reseeding within unpaved parts of the ROW would be performed where required.

Once installation is complete, the pipelines would be placed on the Underground Service Alert one-call grid system prior to being put into service.

2.7.1.8 Hydrostatic Testing

The installed onshore pipelines would be hydrostatically tested after construction and before startup pursuant to Federal regulations (49 CFR Part 192). Hydrostatic testing is a strength and proof test designed to ensure that pipe, fittings, and weld sections maintain structural integrity without failure under pressure. The test section of the pipeline would be filled with water and the pressure would be increased to at least one and one-half times the pipeline maximum operating pressure. The test period would be in accordance with CPUC guidelines. The pipes would be tested in one or more segments depending on elevation, water source, and water discharge facilities. The amount of water required for testing of both onshore pipelines is dependent on the number of test segments to be tested because the water could be reused for each segment. The water would be obtained from a potable water source along the route. Following completion of the hydrostatic tests, the water would be discharged to an existing channel or wash along the route pursuant to a NPDES permit.

Before discharge, the hydrostatic test water would be evaluated to ensure that it meets the NPDES permit standards. SoCalGas would also design and install a suitable energy dissipater at the outlets and design and install suitable channel protection structures to ensure that there would be no erosion or scouring of natural channels within the affected watershed. These structures would be removed from the site upon completion of hydrostatic testing.

SoCalGas would keep permanent records of each hydrostatic test. These records would be accessible to the responsible regulatory agencies and would contain the exact location of the test segment, the elevation profile, a description of the facility, and continuous pressure and temperature readings of the line throughout the test.

2.7.2 Crossing Techniques

During installation of the onshore pipelines, both watercourses and roads would be crossed. Each is described below.

2.7.2.1 Watercourse Crossings

Water crossings would occur at the South Fork Santa Clara River and San Francisquito Creek. None of these three major river crossings would be trenched. As described above, the pipeline would cross Santa Clara River at the McBean Parkway Bridge and San Francisquito Creek at the Avenue Scott Bridge by hanging it underneath the open girder bridges. The pipeline across the South Fork Santa Clara River at the Magic Mountain Parkway Bridge would be installed inside a closed girder bridge. No equipment would enter the stream channel during installation of the pipeline in the Magic Mountain Parkway Bridge.

The pipeline route would span the South Fork Santa Clara River near the intersection of Magic Mountain Parkway and San Fernando Road (SR 126). At this crossing, the 30-inch (0.76 m) diameter gas pipeline would be installed within a 36-inch (0.9 m) diameter casing, which would be installed in an open cell located in the existing Magic Mountain Parkway Bridge.

To access the cell and install the casing and pipeline, a 7-foot (2.1 m) wide by 50-foot (15.2 m) long work trench would be excavated in the roadway adjacent to both the north and south ends of the bridge. Also, approximately four or five holes would be excavated in the surface of the bridge. The entire operation would remain inside the bridge and adjacent roadway; no access or work would be necessary within or underneath the channel or banks of the river. One lane would remain open on the construction side of the bridge so that the non-construction side would not be impacted. A storm water pollution prevention plan (SWPPP), including applicable BMPs, would be implemented to control storm water run-off and concrete cutting drippings. Installation of this pipeline crossing is anticipated to take 55 to 60 days and is estimated to occur between September and November 2009.

At the McBean Parkway (Santa Clara River) and Avenue Scott (San Francisquito Creek) Bridges the pipeline would be attached to the underside of these existing open-girder bridges. Rubber-tired equipment would be staged within the streambed beneath the bridges to assist in attaching the pipeline; no excavation within the streambed would be required. Installation of each of these pipeline crossings is anticipated to take 55 days and is estimated to occur between August and November 2009, when flow in the streambed is expected to be minimal. If present, surface water flows within the channel would be diverted around the construction equipment through the installation of a temporary cofferdam, consisting of several pre-cast concrete barriers supplemented with sand bags, and the procedures used would comply with the SoCalGas Construction Stormwater BMP Manual. Alternatively, SoCalGas would use an equipment bridge to keep equipment from working within any flowing water. Work within the streambed would occur for no more than 30 days.

Depending on final engineering design, instead of crossing the Santa Clara River within the bridge, HDD may be employed. This methodology requires the use of drilling fluid similar to the process for HDB described in Section 2.6.1, “Shore Crossing via HDB.” The HDD crossing would be approximately 2,000 feet (610 m) long. This construction method would require two large staging areas, one on each side of the river; the entry point staging area would measure approximately 200 feet by 400 feet (61 m by 122 m) while the exit point staging area would measure approximately 150 feet by 2,000 feet (46 m by 610 m).

The procedure would be to drill a pilot hole which would then be successively reamed in five to six passes to achieve a 36-inch to 42-inch (0.9 m to 1.1 m) diameter borehole. The prefabricated 2,000-foot (610 m) long, 30-inch (0.76 m) diameter pipeline would then be pulled back through the bore hole in one continuous motion. Installation of a 30-inch (0.76 m) diameter pipeline beneath the Santa Clara River using HDD would take approximately three months, and drilling would be conducted 24 hours per day/seven days per week.

All dry watercourse or minor (30 feet [9.1 m] or less in width) wet crossings would be open-cut-trenched. The open-cut technique would require a trench to be excavated from bank to bank. Equipment such as backhoes, bulldozers, and draglines would be used to excavate the trench. The pipe would be placed below the potential scour depth of the wash channel with an adequate margin of safety to ensure that the pipe is not exposed by wash bed scour. The wash channel would be returned to its original configuration, the substrate would be replaced, and the banks would be stabilized and revegetated as necessary. A U.S. Army Corps of Engineer Clean Water Act § 404 Nationwide Permit No. 12 (Utility Line Discharges) and a CDFG Streambed Alteration Agreement (Fish and Game Code § 1602) would be obtained for watercourse crossings as required. SoCalGas would obtain all necessary permits.

Other crossings, such as at several concrete-lined flood control channels, may require using existing road bridges, spanning over the open channel, or using horizontal boring beneath the channel. Each crossing would be evaluated by SoCalGas construction engineers during final engineering design to determine which of these three methods would be used.

2.7.2.2 Road Crossings

The proposed pipelines would cross several primary roadways as well as SR 1 (Pacific Coast Highway) and U.S. 101 (Ventura Freeway). Most road crossings would be excavated. Before construction, all utilities would be identified and marked. Once traffic control measures were in place, a 7-foot (2.1 m) deep trench would be excavated; previously identified buried utilities would be located first by manual digging and would be measured to determine the trench depth required to clear them. Road crossings would be completed in accordance with the requirements of road crossing permits. Traffic warning signs, detour signs, and other control devices would be used as required by regulatory agencies.

Where excavating is not practical, such as railroad crossings and areas with very wide roadways or roadways with heavy traffic loads, the pipeline would be constructed by conventional boring with a permanent casing. Conventional boring under U.S. 101 (Ventura Freeway) and SR 1 (Pacific Coast Highway) would require bore pits on each side of the highway. The pits would be approximately 25 to 45 feet (7.6 to 13.7 m) long and 8 to 15 feet (2.4 to 4.6 m) wide. The depth of the pits would depend on the final pipeline depth. Excavation spoils would be placed alongside the pits and would be used as backfill. Casing and pipe sections would be welded, inspected, and line pipe coated in the pit before installing. Upon completion of the pipeline installation, the excavated areas would be backfilled, compacted, and restored to natural contours.

2.7.3 Off-Right-of-Way Activities

2.7.3.1 Staging and Storage Areas

There would be two to three temporary staging areas for the Center Road Pipeline and one or two temporary staging areas for the Line 225 Pipeline Loop. The staging areas would be 2 to 8 acres (0.8 to 3.2 ha) depending on availability and landowner approval. They would hold equipment, excess spoils, and contractor offices and materials, and would serve for parking for construction workers. The locations of these staging areas have not yet been selected, but they would likely be in commercial/ industrial areas and as close as practical to the construction route.

The staging areas would be selected by the construction contractor, and all applicable permits would be acquired prior to initiating construction. The staging areas would be sited to take advantage of existing disturbed areas. To avoid impacts on sensitive resources, SoCalGas would conduct biological and cultural resource assessments of the selected sites prior to approving them for use by the contractor.

During all phases of construction, refueling and lubrication of construction equipment would occur along the construction spreads and in the contractor’s staging areas. Staging areas would operate only during daylight hours, unless nighttime construction operations are required by any permit. If night work is mandated, lighting of the staging area would be required. Lighting would consist of temporary portable/maneuverable lights, a pole, a generator, and a light-directing screen. The light would remain on for short periods during loading and unloading of supplies and equipment and would be turned off when the staging area is unoccupied. The staging areas would be enclosed within a 6- to 8-foot (1.8 to 2.4 m) high standard chain-link fence with screening material, if necessary.

No new pipe yards would be required for the onshore Project. The pipe yards to be used are owned by SoCalGas or other entities. The exact locations have not been determined but would likely be in the Fontana and San Bernardino areas.

2.7.3.2 Transportation

Existing roads would be used for all construction-related traffic and equipment mobilization; no new permanent access roads would be needed. Where the routes traverse unpaved areas, temporary access roads and work strips, typically 80 feet (24.4 m) wide, would be required.

Most heavy construction equipment would be delivered to the initial point of the spread on lowboy trucks or trailers. Mobile cranes and dump trucks would be driven to the construction site from the existing local vendor yards. Construction equipment would be left overnight at the site, at contractor yards, along the ROW, along the paved roadway within the construction zone, or at other existing staging yards along the construction spread. All construction materials would be transported to the construction spreads by truck on existing roadways.

An estimated 400 to 450 truck trips would be required to deliver materials and equipment for the Project. All vehicles would be regulation-sized except for pipelaying equipment, which could require oversized loads. The vehicles would include 1-ton (910 kg) flatbed trucks, lowboys, pipe dollies, trailers, and dump trucks. The contractor would be responsible for obtaining local hauling permits with appropriate state and local agencies.

2.8 FUTURE PLANS, DECOMMISSIONING, AND ABANDONMENT

The Applicant's projected FSRU in-service life is a maximum of 40 years, although the Federal license for the proposed DWP would have no expiration date. The Applicant would be responsible for the cost of decommissioning at the end of the Project, and as part of the License the Applicant must demonstrate the financial ability to pay for the decommissioning. The impacts of decommissioning would be evaluated in a separate Project-specific environmental document, pursuant to the National Environmental Policy Act (NEPA) and the California Environmental Quality Act (CEQA), when the Project is no longer viable.

2.8.1 Floating Storage and Regasification Unit and Mooring System

The FSRU would operate as long as it remains in compliance with Federal regulations and the conditions of the license. The FSRU would be inspected annually by a classification society, which would also conduct a special survey after five years of operation and every five years thereafter.

Upon decommissioning, the FSRU would be removed from the mooring point and towed to a shipyard to be overhauled and recertified or to be scrapped and salvaged as appropriate. Before removal from the site, all gases would be removed from the entire FSRU, including LNG in the Moss tanks and natural gas from the process, mooring, riser, and pipeline systems. Depending on the component or system, the gases would be purged using inert gas, followed by purging and ventilating with air or flooding with water; any necessary permits would be acquired. The flexible risers and the mooring legs would be disconnected from the FSRU bow turret and attached to a marker/pickup buoy. The FSRU would then be towed away using oceangoing tugs.

Ocean floor anchors would be removed or left in place, depending on anchor type, ocean floor environmental conditions, and regulatory requirements applicable at that time. Mooring cables, the mooring turret, flexible risers, and the PLEM would be removed and brought to shore for final salvage or other appropriate disposal.

2.8.2 Offshore Pipelines

In both Federal and State waters, the pipelines would be evaluated to determine whether removal or abandonment would provide the most environmental benefit. Subsea pipeline abandonment would begin with pigging the line to remove any debris, scale, or other materials. If the pipelines were to be removed, they would be cut, raised to a salvage barge, and brought to shore; if not, they would most likely be filled with an inert gas and sealed before being abandoned in-place. The subsea pipelines within State waters that were drilled using HDB would also most likely be filled with an inert gas, sealed, and abandoned in-place.

2.8.3 Shore Crossing and Onshore Pipelines and Facilities

When the pipelines were no longer required they would be abandoned in-place or removed in accordance with agency requirements. If abandoned in-place, the pipelines would be cleaned to remove any liquids, filled with an inert gas, and sealed.

The onshore meter, the main line valve, the odorant injection facility, and any other aboveground facilities would be removed and scrapped or salvaged as appropriate.

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